The Province of Alberta

PETROLEUM AND NATURAL GAS CONSERVATION BOARD

IN THE MATTER OF THE GAS RESOURCES PRESERVATION ACT

AND IN THE MATTER of a Joint Hearing to determine various questions relating to the proposed Export of Natural Gas from the Province of Alberta.

I. N. McKinnon Esq., Chairman

D. P. Goodall Esq.

Dr. G. W. Govier

Session: October 30, 1950.

Volume 1.

I N D E X

J O I N T H E A R I N G

VOLUME 1

30th October, 1950.

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Hearings on the above Matters before I.N. McKinnon, Esq., Chairman, and D. P. Goodall, Esq., and Dr. G.W. Govier, at the Court House, Calgary, on the 30th day of October, A.D. 1950.

VOLUME 1.

October 30th, 1950.

THE CHAIRMAN: We announced at the last Sitting that we would not sit on Fridays, but we would sit on Thursday afternoons instead. The Board is unable to sit on Thursday afternoon this week but we are prepared to sit on Friday morning. Now, if it will inconvenience any counsel we would like to know.

MR. NOLAN: So far as I am concerned, Mr. Chairman, we will be quite glad to meet the convenience of the Board and sit on Friday morning if the Board so desires because we are very anxious to conclude these Hearings.

THE CHAIRMAN: It is very unfortunate we are not able to sit on Thursday.

MR. FENERTY: Whatever the Board says.

MR. STEER: Yes.

THE CHAIRMAN: Well, we will sit on Friday. We propose to start a new set of exhibits and prefix them by the letter "J". I think that will avoid confusion with the exhibits in other Hearings. Mr. Steer?

MR. STEER: With the Board's approval I propose first to call Mr. Brownie to give his up-to-date report on estimated requirements of the two companies. Mr. Brownie.

FRANK AUSTIN BROWNIE, having been first duly sworn, examined by Mr. Steer, testified as follows:

Q Mr. Brownie, I think if you read this report the connection with what you previously had to say on this question will appear. Perhaps you will just read your report.

THE CHAIRMAN: We might enter this as Exhibit J-1.

ESTIMATED MARKET REQUIREMENTS AND PEAK DAY LOADS 1950-1980 MARKED EXHIBIT J-1.

A THE WITNESS: This report is entitled "Estimated Market Requirements and Peak Day Loads 1950-1980".

A previous report, which was prepared on December 30th, 1948, (Exhibit 41), fully outlines the method used in estimating future market requirements at 1960. A subsequent report, dated January 27th, 1950 (Exhibit 42), was submitted to the Petroleum and Natural Gas Conservation Board, and constituted a revision of the previous estimates.

In preparing the present estimates these previous computations were reviewed, taking into account actual

experience up to date. It is considered that such present experience does not indicate any necessity to change further the estimates prepared on January 27th. The factors affecting the quantities designated as Domestic, Commercial and Industrial for the two Companies on Statement "C" of the January 27th report are very closely in line with the trends projected at that time. It is true that in respect to some of the additional industrial loads there has been some reduction in the expected volume of business, but it is considered that in view of the conservative provision for such loads in the future, and new prospects unforeseen at that time, no reduction of the previous estimates is warranted.

The only change, therefore, that has been made in the present report in respect to 1960 estimates is to include some portion of the market requirements shown under the heading "Province Generally - Additional Possibilities" on Statement "C" of the January 27th report, with the requirements of our respective Companies. 2 billion cubic feet have been added to Northwestern, and 3 billion to Canadian Western, since it is considered that such loads, if they materialize, will be added to those systems.

Q MR. STEER: Mr. Brownie, would you there let us know whether or not any consideration has been given to industrialization of the Province due to dispersal of industry?

A No, no provision was made of anything of any extraordinary nature such as that.

In projecting the market requirements beyond

1960, reference is made to the graphs, Figures 1 and 2, showing the population of Calgary and Edmonton respectively in the report of December 30th, 1948. Revised graphs are included in the present report, showing the previously estimated growth in population of these two Cities and also the most recently available data. This latest information indicates that as of the present time the previous projection was, if anything, conservative. It is considered, however, that the previous estimates for 1960 population are still reasonable, and should not be increased. As shown, the projection of population to 1980 has been made by extending through the 1960 points a line representing the long term increase in population, and results in an average annual increase in the population for Calgary of 1.6% of the 1960 figure during the period 1960 to 1980. The corresponding figure for Edmonton is an average annual increase of 1.8% of 1960 population during that period. Due to the impossibility of predicting specific loads that might be added at a time so far in the future, it has been assumed that the growth in market requirements for the two systems will be at the same rate of increase as the population. Consequently, the estimated requirements for the two systems in 1980 represent an increase of 20 years at 1.6% or 32% of 1970 total requirements in the case of Canadian Western, and 20 years at 1.8% or 36% of 1960 total requirements in the case of Northwestern.

At the request of the Board, the present estimates have been prepared on a year by year basis. This has

been done by plotting actual requirements up to 1950 on graphs, Figures 3 and 4.

Q Would you like to refer to those now, Mr. Brownie?

A Referring to Figure 3, it will be noticed that the 1940 point is plotted; the 1945 point is plotted, actually adjusted to normal temperature; the 1949 point is plotted and a point for 1950 which is based on actual experience to date and estimates for the latter months of the year. Then the 1960 point is shown. That point was obtained as already described in the text, and the curve was projected from 1960 as described and between 1950 and 1960 a smooth curve was drawn. The same method was adopted in the case of Northwestern as indicated on Figure 4. Going on with the text:

The estimates for 1960 and projection to 1980 were then plotted and a smooth transitional curve drawn between the 1950 and 1960 points. Yearly figures were then read from this curve.

In order to estimate the peak day loads of the two systems through 1980, a previous estimate for the year 1960 for each of the Companies was reviewed. In the case of Canadian Western this amounted to 200 million cubic feet per day, and was determined by applying the present load factor experience of Domestic, Commercial and Basic Industrial sales to the corresponding figures for 1960. Estimates of the load factor of the special industrial loads were made on the basis of an individual determination of the character of these loads. The present estimate of 215 million cubic feet per day was obtained by adding to

the previous figure an estimated peak for the additional 3 billion cubic feet of annual sales at a load factor consistent with the load factor of all the special industrial business included in the previous estimate. The resulting ratio of annual sales to peak day loads is 160. In examining the corresponding ratio resulting from 1950 annual requirements and estimated peak day load for the winter of 1950-1951, this was found to be 154. Since it is impossible to predict accurately year by year the load factor of new business expected to be added, the ratio during the period 1950 to 1960 was therefore determined by a straight line increase from 154 to 160. Beyond 1960 the ratio was taken as being constant at 160.

In respect to the estimated peak day loads for Northwestern, an examination of the ratio of 1950 annual requirements and estimated peak day load for the winter of 1950-1951 indicated this to be 137. During the next two years the effect of the increasing consumption at the City of Edmonton Power Plant will tend to increase this ratio to an estimated level of 149 in 1952. It is considered that there is no reason to suspect that the load factor of Northwestern Utilities' system should be any less favorable in the long term than that of Canadian Western. It is at the present time lower due to a greater proportion of domestic and commercial business, but the increase in industrial load at the present time is at a very substantial rate, and it is therefore assumed that the ratio for Northwestern will increase to 160, the same as Canadian Western, by the year 1960. This increase has therefore been projected

F. A. Brownie,
Dir. Ex. by Mr. Steer.

on a straight line basis during the intervening period, and is similarly projected at 160 beyond the year 1960.

Year by year figures for annual requirements and peak day loads are shown on the following statements. They are shown on pages 4 and 5 of the report.

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

Annual Market Requirements and Peak Day Loads
(All quantities @ 14.4 psia and 60°F.)

Year	Annual Market Requirements MMMCF.	Year End Peak Day Loads - MMCF
1940	7.9 (1)	60.9 (3)
1945	16.2 (1)	83.6 (3)
1949	19.1 (1)	132.6 (3)
1950	21.0 (2)	145
1951	23.2	160
1952	24.9	171
1953	26.4	180
1954	27.6	188
1955	28.6	194
1956	29.5	200
1957	30.4	205
1958	31.1	209
1959	31.8	212
1960	32.4	215
1961	32.9	219
1962	33.4	223
1963	34.0	226
1964	34.5	229
1965	35.0	233
1966	35.5	236
1967	36.1	240
1968	36.6	243
1969	37.1	247
1970	37.6	250
1971	38.1	253
1972	38.6	257
1973	39.2	260
1974	39.7	264
1975	40.2	267
1976	40.7	270
1977	41.2	274
1978	41.8	277
1979	42.3	281
1980	42.8	284

F. A. Brownie,
Dir. Ex. by Mr. Steer.

Notes:
(1) Actual, adjusted to normal temperature.
(2) 8 months actual, 4 months estimated, - adjusted to normal temperature.
(3) Actual.

BWS:JDW
Oct. 17/50

NORTHWESTERN UTILITIES,LIMITED

Annual Market Requirements and Peak Day Loads
(All quantities @ 14.4 psia and 60°F.)

Year	Annual Market (1) Requirements MMMCF.	Year End (1) Peak Day Loads - MMCF
1940	3.9 (2)	29.6 (4)
1945	8.2 (2)	55.5 (4)
1949	15.2 (2)	120.8 (4)
1950	19.8 (3)	145
1951	23.3	166
1952	26.5	178
1953	28.5	190
1954	30.2	200
1955	31.5	207
1956	32.6	213
1957	33.6	218
1958	34.4	221
1959	35.2	223
1960	35.9	225
1961	36.6	229
1962	37.2	233
1963	37.9	237
1964	38.5	241
1965	39.2	245
1966	39.8	249
1967	40.4	253
1968	41.0	257
1969	41.7	261
1970	42.3	265
1971	43.0	269
1972	43.6	273
1973	44.3	277
1974	44.9	281
1975	45.6	285
1976	46.2	289
1977	46.9	293
1978	47.5	297
1979	48.2	301
1980	48.8	305

Notes:
(1) Based on calorific value of Kinsella gas.
(2) Actual, adjusted to normal temperature.
(3) Budget estimate.
(4) Actual.

F. A. Brownie,
Dir. Ex. by Mr. Steer.

MR. STEER: It won't be necessary, I take it, Mr. Chairman, to read those figures.

MR. NOLAN: I wonder if I could make one comment on Mr. Brownie's evidence so far as my client is concerned. We have accepted, sir, as the basis of our estimate of the gas reserves the previous statements or estimates which have been made by the two local gas companies. This statement today, which has been furnished to us by Mr. Brownie, differs only slightly from the previous estimates and we feel that it would not be of assistance to the Board and that we might be wasting the Board's time were we to go into an elaborate cross-examination at this stage, so we prefer, sir, to point out and to cover any differences that there may be in the direct testimony which we will offer later in the joint Hearing.

MR. STEER: Well now, Mr. Chairman, if my learned friend is suggesting that in the view of his clients these estimates are not accurate to the extent that they can be made accurate, having in mind what they are, my suggestion is, for the benefit of the Board and in fairness to Mr. Brownie, there ought to be indicated to him at least the respects in which it is proposed to suggest that these estimates are not accurate.

THE CHAIRMAN: I presume that will be done?

MR. STEER: Pardon, sir?

THE CHAIRMAN: I was talking to Mr. Nolan. I presume, Mr. Nolan, you intend to outline any differences at the time you give your direct testimony on deliverability?

MR. NOLAN: Yes, sir, and the differences, as I have pointed out, are slight and we are in no marked disagreement with what Mr. Brownie has said; and it is for me to decide whether I am going to ask Mr. Brownie any questions on his statement or whether I am not, and I will present my own case in my own way.

(Go to page 11)

MR. STEER: The Board sees, of course, that the only result of that course of procedure is that eventually Mr. Brownie may have to come back into the box to reply and, with all respect to my learned friend, that is not the normal way that proceedings are conducted. If my learned friend had Mr. Brownie in a Court Room, he, I think, would be obliged to put in in cross-examination the points of difference.

MR.NOLAN: Well, I was never compelled to cross-examine a witness yet and I do not think I will be now.

THE CHAIRMAN: Does somebody wish to question Mr. Brownie?

MR. FENERTY: I might put in one word. According to my figures the difference in the measurement amounts to 4.6% instead of 5%. Now, I do think that if any applicant is going to present figures based on the lower figures, they should at least by cross-examination justify them.

MR. C. E. SMITH: Might I suggest, sir, that I agree with Mr. Nolan. I do not know how anybody can force him to cross-examine a witness. He is taking a chance, I think, and the other people are not. If he wants to take that chance and submit something later without cross-examination of Mr. Brownie, he probably will not get the opportunity to do so later.

MR. McDONALD: Mr.Chairman, I just have a few questions now.

THE CHAIRMAN: Yes.

....

CROSS-EXAMINATION BY MR. McDONALD:

Q Mr. Brownie, you mentioned something when Mr.Steer questioned you with regard to the dispersal of industry, and if you had given any consideration to it. Do I take it that you are referring to the question of industry in accordance with some master plan of some kind, or just how industry goes in its ordinary course?

A I understood Mr. Steer was referring to a possible dispersment of industry such as we hear of in other places, perhaps for defence reasons and perhaps for economic reasons.

Q Do I take it that you have added the additional requirements for the Province generally to the estimates in your particular submission on the assumption that this dispersal of industry will eventually be taken into account in your submission?

A No. We had in our earlier reports certain industrial loads which were not assigned to any particular place. I think they were under the heading of "Province Generally", and when we came to projecting year by year consumption for our two companies, we thought it only reasonable to assign certain of those loads to our companies because we could not see any place else where they might go.

Q Well, would you agree with me this far, if there is dispersal of industry there is more possibility of such dispersed industry being served from local and small fields other than from these large reserves which are now the subject as a source for your company?

Q No, I wouldn't agree with that, Mr. McDonald. I think

Mr. Steer was referring to a dispersal of industries which are presently in Eastern Canada, perhaps, or perhaps in the United States, that might come to Alberta.

Q Yes?

A And thereby increase the trend towards the industrialization of this Province.

Q Now, it is by adding 2 billion cubic feet to Northwestern that you get the increased peak demand for 1960 over your previous estimate?

A That is correct.

Q And, similarly, the three billion additional to Canadian Western gives you the increased demand from 200MCF to 215 MCF?

A That is correct.

Q Now, you referred to the fact that your previous estimate in industry was excessive insofar as experience has shown up to date?

A In certain respects, yes.

Q Now, if you had applied the actual experience in the period between the date of your estimate and the present time, would that have reduced your 1960 estimate?

A No. This Canadian Western system actually took on less power plant business than we had anticipated. The Northwestern system received less increase in oil refinery business than we had anticipated. Those things taken by themselves would have tended to decrease our 1960 estimates, but, as we point out here, a number of other prospects have appeared that we did not foresee at the time the earlier estimates were prepared, and we see no reason to change the earlier figures.

Q I am just interested now in the question of the power load, and taking Edmonton, do you anticipate the requirements for power in Edmonton will be in direct proportion to the increase in population?

A No, I do not think so, Mr. McDonald. I do not have all the details of the earlier reports at my fingertips at the moment, but, as I recall it, we assigned certain specific amounts to the Edmonton power plant.

Q Yes, go ahead, Mr. Brownie?

A We had certain information as to the number of boilers which were going to be converted to gas and which were going to be built and fired with gas, and we put that amount of load into our estimates.

Q MR. C. E. SMITH: Do you want to see that last exhibit, Mr. Brownie, by any chance?

A I have it here.

Q I am sorry. I thought you did not have it.

Q MR. McDONALD: The way that you have made your estimate here, you have given full effect to the increase in the Edmonton load because of power additions. Now, you have carried on your curve, or your graph carries on, and the net result is that you have given effect to an accelerated increase in power load right through to 1980 on the basis that you have had in the last three years?

A Yes, I think that is right, from 1960 to 1980.

Q Well, the only thing I am questioning is, I do not know that that is a reasonable assumption to suggest a power load in the Edmonton system is going to increase at the rate of four or five billion, as it were, for the last three years. The exact figure in your estimate is,

City power plant $3\frac{1}{2}$ billion, it will be roughly 3 billion, do you think that ratio should be carried through for the last 30 years just because it occurred in 3 years?

A Well, I think it is reasonable to assume this, that if we have a certain figure in for power plant business in 1960, whatever it may be, I do not recall at the moment, but if the city continues to increase in population at the rate of 1.8% per year, and if they continue to use gas to produce power, the power will go up 1.8% per year.

Q That is the question I asked you to start with, Mr. Brownie, and I understood that your answer was that that was not so.

A That was not so up until 1960. I was talking about 1960. We put in a specific assigned figure for the power plant business.

Q Yes?

A Now, as you point out to me, if we do increase that amount 1.8% beyond 1960,and I think that is a reasonable thing to do.

Q Now, I am interested, Mr. Brownie, in the rate of increase your curves show, and if you had distributed power over the first ten or fifteen years in the operation of your plant and got a curve of that nature, and if you will notice in your estimate of your Northerwestern Utilities that inthe year 1949 to '50 you have got an almost vertical increase.

A What curve were you talking about, Mr. McDonald?

Q At Figure 4?

A You are looking at Figure 4 which is a curve showing markets.

Q Yes, that is consumption?

A The 1960 point in respect to the power plant business is arrived at by putting in what we thought would be consumed by the boilers burning natural gas in the power plant at that time.

Q Yes?

A Now, the population from 1960 on, the curve is based entirely on our idea of what is going to happen to the population. Now, if they burned X billion cubic feet a year in the power plant in 1960, why shouldn't it increase 1.8% each year for the population increase at that rate.

Q Well, I don't know, but your opinion is that it will?

A Yes.

Q Now, let us take a look at your figures in your Exhibit 42. Now, you have in Statement C a total of 31.5 billion for the year 1960 for Canadian Western?

A Yes.

Q Now, you have included in that an allowance for the increase in population, you have added the Imperial Oil Refinery, Alberta Nitrogen, Taber Sugar Refinery at 6.3 billion, you have also added the power plant load of 2.2 billion, and then you have also additional possibilities at 4.5. Then you have additional possibilities, they are 50% of your peak load?

A Additional possibilities?

Q 4.5?

A Yes, that is right. That includes 2½ billion feet per annum for Banff and Exshaw too.

A Yes?

A It includes half a billion for Raymond, including the Sugar factory. It includes 400 million for Picture Butte,

including the Sugar factory, and it includes certain railway business which is not served with gas and it might very well be. Those items I have mentioned are the biggest part of the 4½ billion, and I think it is a very realistic estimate.

Q And you have changed the Province Generally item, 6 billion, the second last item on the page, you have added your proportion of that?

A Yes, that is correct.

Q And, similarly, in Northwestern you have added the same items. You have the Imperial Oil Refinery, the City power plant, 4.5 billion, and how much of that has actually been taken up at this time?

A I do not know offhand, Mr. McDonald. I notice I have a figure here of the estimate for 1960, and it is 3,451,000 MCF out of the 4½.

Q Does that include all the power installation that is intended to be put in the Edmonton plant?

A No, I don't think so.

Q Is there still another boiler that can be added?

A I am not certain of that at the moment, Mr. McDonald.

Q Have the Fort Saskatchewan, Oliver, and the Namao installations been completed?

A Fort Saskatchewan, the pipe line has been included. I don't know whether it is in there yet. the pipe line is completed to Oliver, I do not know whether it is using gas yet, and so is the pipe line to Namao.

Q Isn't there some possibi ity that the Namao pipe line can be served with wells in the immediate vicinity other than from the main system?

A There might be a possibility, but we have a go-ahead from the Dominion Government to put it in next Spring.

Q I am not suggesting that any company will do it, but if your company will acquire the gas from wells adjacent to there?

A We have the pipe under order to put in from our existing system next spring.

Q Now, there is one other thing, Mr. Brownie, I was going to ask you about, and that was that I noticed by reports that the Northwestern Utilities Limited have acquired the interests of Imperial Oil Company Limited in the Viking-Kinsella field?

A That is correct.

Q That is correct?

A Yes.

Q And can you tell me what was paid for that?

A As I recall it, $2,890,000.00.

Q And that included the leases, I presume, and the wells that were in existence?

A That is correct.

Q How many wells were there, can you tell me?

A I do not remember, Mr. McDonald.

Q Now, just what was the quantity of reserve which your company considered it had acquired in that transaction?

A Roughly half of 600 billion cubic feet.

Q The figure that I have 278 billion?

A Yes, that could be it.

Q My recollection is that there were 21 wells drilled by the Imperial Oil in the area, and included in your transaction, is that correct?

A We did not buy all the wells that were drilled. We drilled some outside of the commercial area. We only bought those in the commercial area. I think you could tell that from Mr. Davis' report.

Q If it is not available I will ask you for it?

A Yes.

Q I think that is all, thank you.

MR. S. B. SMITH: I have no questions, sir.

MR. C. E. SMITH: I have just one, sir.

....

CROSS-EXAMINATION BY MR. C. E. SMITH:

Q Mr. Brownie, do I understand you correctly that Statement C in Exhibit 42 is only now amended by the third paragraph on page 1 of your last submission, Exhibit J-1, is that correct?

A Yes, we simply took out of that Province Generally section down towards the bottom of Statement C.

Q Yes?

A 2,000,000 cubic feet assigned to the pulp and paper plant and put it in the Northwestern system.

Q Yes?

A And the 3,000,000 Provision for other industrial enterprises as put in the Canadian Western system. There was one other very minor adjustment. We reduced Canadian Western slightly to bring it to 14.4 pounds and 60° basis, but it is a matter of no importance.

Q Otherwise Statement C of Exhibit 41, or 42, is as it was before, is that correct?

A That is correct.

Q That is all, thank you.

....

Q DR. GOVIER: I wonder if I might ask you one question relating to your Exhibit J-1 which you read this morning and which gives us your picture of the growth of the Edmonton and Calgary systems and their attached load. Have you any further views on the growth, or possible growth, of other systems and any other requirements of the Province beyond your systems?

A No, we have not given any consideration to that.

Q THE CHAIRMAN: Mr. Brownie, in regard to the Edmonton Power Plant, are they not in a position at the present time where they produce more than the needed power to meet the city's requirements and sell or export from that plant?

A I am not sure about that.

Q And the figure which you have set is more or less geared to the capacity of the plant?

A I do not believe it provides for converting all of the boilers to gas. But subject to that limitation it is geared to the capacity of the plant.

Q Thanks.

MR. STEER: Mr. Davis.

RALPH E. DAVIS, having been duly sworn, examined by Mr. Steer, testified as follows:-

Q Your occupation, Mr. Davis?

A I am a consultant in natural gas and petroleum fields.

Q In order to save time, you recently gave evidence before the Federal Power Commission and in the course of that evidence recited what your qualifications were?

A I did.

Q Will you read that out to us and tell us whether it is true?

THE CHAIRMAN: I think we will accept Mr. Davis' qualifications. They are well known to this Board.

Q MR. STEER: There is one thing I would like to bring to the Board's attention. What has been your connection with the financing of natural gas undertakings in the United States and Canada over your experience?

A My first connection with a problem of that kind was in 1925, and since that time I have been frequently employed to study gas supplies available to a proposed pipe line or a proposed enlargement of a pipe line capacity. I believe it is fair to state that any financing of that type that has been accomplished during the years from 1925 until now, for both Canada and the United States, I believe that my studies have been relied upon in not less than 75 per cent of such undertakings.

Q And in Canada?

A Nearly all in Canada, at least for the last 15 years, sir.

Q Now, to come down to the local situation, the Canadian Western and the Northwestern both have had large issues during the past few years. Have you been connected with those?

A I have been connected, I believe, with the financing of both of those companies since 1925.

Q Then under date of October 30th, 1950 you prepared a study of the gas supply of the Canadian Western system and the Northwestern system?

A That is right.

Q And in studying that question of supply you also studied the question of deliverability?

A To the extent that that was essential I did, sir.

Q You will read to the Board the result of your studies.

STUDY OF GAS SUPPLY, CANADIAN WESTERN NATURAL GAS COMPANY LTD. AND NORTHWESTERN UTILITIES' LTD., PRESENTED BY MR. DAVIS, NOW MARKED EXHIBIT J-2.

A You have indicated that I should read this report to the Board.

Q That is right, Mr. Davis.

A The report is titled "Study of Gas Supply, Canadian Western Natural Gas Company Limited and Northwestern Utilities, Limited. Prepared for Submission on October 30, 1950, to the Petroleum and Natural Gas Conservation Board, Alberta, Canada."

The problems related to the subject of this report are not easy to analyze with the exactness that could be desired, partly because there is an inter-relation between the several aspects of the broad problem to be met. It is essential at the outset to have a fair idea of the quantities of gas that will be needed by each utility, both annually and on peak days, for many years to come. This most difficult problem has been handled by the staffs of the two Companies, and their estimates of probable requirements, made by years 1950 to 1980, is presented as the estimate of future requirements used by me.

The problem of meeting the anticipated gas requirements of the two utilities is handled for each separately.

Q And then you gave from Mr. Brownie's report the figures on page 2 and the graph attached and the figures on page 4 and the graph attached. Those are taken from Mr. Brownie's report that has been filed as Exhibit J-1?

A That is right.

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

Annual Market Requirements and Peak Day Loads
(All quantities @ 14.4 psia and 60°F.)

Year	Annaul Market Requirements - MMMCF	Year End Peak Day Loads - MMCF
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1972	38.6	257
1973	39.2	260
1974	39.7	264
1975	40.2	267
1976	40.7	270
1977	41.2	274
1978	41.8	277
1979	42.3	281
1980	42.8	284

Notes:
(1) Actual, adjusted to normal temperature.
(2) 8 months actual, 4 months estimated,-adjusted to normal temperature.
(3) Actual.

R. E. Davis,
Dir. Ex. by Mr. Steer.

NORTHWESTERN UTILITIES, LIMITED

Annual Market Requirements and Peak Day Loads
(All quantities @ 14.4 psia and 60°F.)

Year	Annual Market (1) Requirements - MMMCF	Year End Peak (1) Day Loads - MMCF
1940	3.9 (2)	29.6 (4)
1945	8.2 (2)	55.5 (4)
1949	15.2 (2)	120.8 (4)
1950	19.8 (3)	145
1951	23.3	166
1952	26.5	178
1953	28.5	190
1954	30.2	200
1955	31.5	207
1956	32.6	213
1957	33.6	218
1958	34.4	221
1959	35.2	223
1960	35.9	225
1961	36.6	229
1962	37.2	233
1963	37.9	237
1964	38.5	241
1965	39.2	245
1966	39.8	249
1967	40.4	253
1968	41.0	257
1969	41.7	261
1970	42.3	265
1971	43.0	269
1972	43.6	273
1973	44.3	277
1974	44.9	281
1975	45.6	285
1976	46.2	289
1977	46.9	293
1978	47.5	297
1979	48.2	301
1980	48.8	305

Notes:
(1) Based on calorific value of Kinsella gas.
(2) Actual, adjusted to normal temperature.
(3) Budget estimate.
(4) Actual.

Q Then will you proceed on page 6?

A Northwestern Utilities, Limited.

Gas Supply

The supply of this Company for the period 1923-1939 was obtained in the Viking field. Since 1940 the supply has come increasingly from the Kinsella field. The two fields are separated by name, and are operated essentially as two fields, although they are parts of one field, and deliver gas to the same pipe line system.

The writer has enjoyed a long familiarity with both fields, and has had occasion many times to study the reserves, the deliverabilities, the number of wells required for increasing needs, and other related problems. The most recent of these prior studies was completed January 6, 1949, giving a reserve estimate as of September 30, 1948. A review of that study in the light of developments to date has just been completed. Since no change in the conclusions seem at this time justified, a copy of that report is submitted as a part of this report.

The recoverable reserves of the Viking-Kinsella field as of January 1, 1950, are estimated at 612.5 billion cubic feet (the estimate being made to 200 pounds square inch gauge pressure assumed as the abandonment pressure.)

Regarding future deliverability from the Viking-Kinsella field, I will point out that since the acquisition by contract of notable gas supplies in the Leduc field, the question of deliverability from an economic spacing of wells at Kinsella is related to the peak day deliveries to be expected from Leduc. We can get as many answers as we are willing to make assumptions. The best assumption,

I believe, will be based upon an economic ultimate spacing of wells at Kinsella.

It happens that in the determination of the number of wells to be drilled at Kinsella each year, Northwestern now employs the use of back-pressure potential tests, and these have been made and are available from 44 Kinsella wells. A typical such test is presented herewith in compliance with the request of the Board. An average of the 44 back pressure tests has been compiled, which indicates that when the average top of well pressure is reduced to 200 psig the average well will have a potential or open flow capacity of 1,176 Mcf per day (on a ten-day stabilized basis). Assuming a gathering system powered to recover on peak days 25% of the potential, it is seen that with 150 wells the daily delivery would be 44.1 MMcf.

Q And where is that to be found? At page 21, I think, of your report?

A Is it on the last page? Page 21.

Q I think this might perhaps be the place in which you might discuss the making of those back pressure tests?

A Somewhere here I have a detailed statement regarding that.

Q This is it?

A You have it there. At the outset, in explanation of the method herein described or to be described, I may say that it is based upon the work of the U.S. Bureau of Mines, as described in their published Monograph No. 7, and that the work has also been carried on here by the staffs of the two utilities named by following the fundamental principles

enumerated or set out in Monograph 7 and following also the refinements that have been worked out by Mr. C. W. Binckley and his associates, who have done some very notable work in this field. The tests made in the Kinsella wells are made by an engineer of Northwestern Utilities and this description that I propose now to read of that method was prepared, not by me, but I present it as having come to me as part of the information available to me. I will read it.

The method of back pressure testing used by Northwestern Utilities Limited, is based on Monograph 7 of the U.S. Bureau of Mines and the work of C. W. Binckley of the Phillips Petroleum Company as published under the titles of "Open Flow and Back Pressure Data and Their Application to the Production of Natural Gas -- With Particular Reference to the Data Obtained in the Hugoton Field" (June 1st, 1946), and "Back Pressure Testing of Gas Wells Producing from Formations of Low Specific Permeability" (September 15th, 1947) and "Method of Establishing a Stabilized Back-Pressure Curve for Gas Wells Producing from Reservoirs of Extremely Low Permeability."

The appended calculation sheet indicates the testing procedure followed. It will be noted that four three-hour flows were carried out in normal sequence, that is, beginning with the lowest flow and increasing to the greatest flow. The data calculated from these flow tests were plotted up to give curve 1 on Figure 1, - that curve being attached here - which is a graph indicating the deliverability of the well at the end of a 3-hour flow

period.

Since wells in the Kinsella field are not stabilized at the end of three hours, and since they may be called on to deliver gas at the maximum permissible rate for as long as ten days at times of peak, it is necessary to calculate the deliverability curve for the wells which represents their ability to produce gas after having been flowed at a steady rate for 10 days. The data for this purpose are obtained during the first 3 hours of flow by taking readings of pressure and temperature at the critical flow prover at frequent time intervals during the three-hour period. These data are plotted as a curve on Figure II. The curve so plotted can then be extrapolated to indicate the flowing pressure at the end of 240 hours, and the flow at the end of this period can be calculated by using this pressure in the critical flow prover equation. The point determined in this manner is plotted on Figure I, and a line drawn through it parallel to curve 1. This line, which is shown as curve 2 on Figure I, represents the deliverability of the well after having been flowed at a steady rate for ten days.

For any calculations of field deliverability the individual ten-day well head deliverability curves for the wells are used. By estimating the reservoir closed pressure and calculating the gathering line or back pressure at the individual well, the volume of gas that will be delivered by the well can be read directly from the ten-day curve.

It will be noted that Northwestern Utilities

data are based on well head conditions rather than bottom hole conditions of pressure. It was found by calculation that a deliverability curve for a particular well based on bottom hole conditions was very nearly parallel to a curve based on well head conditions, indicating that the friction in the flowing string was very low under normal operating conditions. Since the use of well head pressures reduces the calculation involved, these pressures were subsequently used.

THE CHAIRMAN: I wonder if this document that Mr. Davis has read from might be entered as an exhibit.

MR. STEER: Yes, sir.

STATEMENT RE BACK PRESSURE TESTING OF GAS WELLS IN THE KINSELLA FIELD READ BY MR. DAVIS IS NOW MARKED EXHIBIT J-3.

MR. C. E. SMITH: What might we call this, Mr. Steer?

MR. STEER: Method of Back Pressure Testing.

(Go to page 30)

Q MR. STEER: Then will you proceed.

You told us your opinion as to that method of making back pressure tests, Mr. Davis?

A No, I do not believe I answered that point.

Q What is your answer?

A I have become quite familiar with the work as carried out and as described in this Exhibit J-3 through my associations with Mr. Binckley in his studies in the Hugoton Field. I believe the method here described is entirely acceptable. I know of no way to determine the capacity of a well to produce by any method other than this other than to actually flow the well to the atmosphere and thus determine its potential.

Q Yes. Then will you proceed on page 7.

A An average of the 44 back pressure tests has been compiled, which indicates that when the average top of well pressure is reduced to 200 psig the average well will have a potential or open flow capacity of 1,176 Mcf per day (on a ten-day stabilized basis). Assuming a gathering system powered to recover on peak days 25% of the potential, it is seen that with 150 wells the daily delivery would be 44.1 MMcf.

The assumption of a total of 150 wells is arbitrary. It would be an average spacing of 1 well for each 2.5 square miles. For a field of such limited reserves, about 3 million cubic feet per acre of economically recoverable gas, such spacing appears economical and logical. It compares with a spacing program in the Hugoton Field of 1 well per square mile, where the recoverable reserves are estimated at 7 to 8 MMcf per acre.

Whenever the peak day delivery from Viking-Kinsella has fallen below the peak day demand, the balance of requirements must come from Leduc or from some other field.

Comparison of Estimated Market Requirements with Total Viking-Kinsella and Leduc.

The combined recoverable pipe line gas reserves of these two fields are estimated by me, as of January 1, 1950, at 1222 MMMcf. The estimate of gas requirements as presented by Northwestern totals 331.5 MMMcf to the end of 1960, 726 MMMcf. to the end of 1970, and 1185 MMMcf. to the end of 1980.

Experience in many gas fields has shown that an average of 85% to 90% of the total gas in the reservoir is economically producible. I believe that it will be less than 85% at Kinsella and close to 90% in the gas cap at Leduc. Experience has also shown that in the average field reduced withdrawals begin when the field is about 65% depleted, or when about 75% of the economically recoverable gas has been withdrawn. Considering the combined recoverable pipe line gas of the two fields, Kinsella and Leduc, to be the total at January 1, 1950, of 1222 MMMcf mentioned above, plus the past production at Kinsella of 130 MMMcf, and past production at Leduc of 42 MMMcf, or a total of 1394 MMMcf, we reach the 75% depletion of recoverable reserve figure when 1045 MMMcf. has been withdrawn. This would occur, according to the arithmetic, in 1974. After that date it would be difficult to satisfy peak demands at reasonable cost.

Conclusions

1. Market requirements as estimated by Northwestern Utilities, Limited, indicate a requirement 1950 through 1980 of 1185 MMMcf.

2. Total pipe line gas economically available at Kinsella is placed at 612 MMMcf.,at Leduc at 610 MMMcf., a total of 1222 MMMcf. as of January 1, 1950.

3. Decline in deliveries from these combined fields would naturally begin if development were carried out according to usual practice and no arbitrary abridgements intervened, when about 873 MMMcf. of pipe line gas has been withdrawn in addition to the 172 MMMcf. withdrawn up to January 1, 1950. Since the gas cap at Leduc must be largely conserved until the oil is produced, we must depend upon Kinsella to carry the major share of peak deliveries during the next 10 to 15 years. The econonical drilling program at Kinsella will probably of necessity be completed before 1960, and after that time peaks can be met from the two fields only if Leduc gas cap wells be used to the extent necessary on peak days.

4. The gas cap at Leduc is not expected to be available except possibly for emergency peak demands until after 1970, or possibly after 1975.

5. To meet this situation, a field with substantial reserves and deliverability should be acquired by Northwestern not later than 1960 if it expects to supply the estimated demands through the period when

Leduc gas cap gas is withheld.

6. To meet the estimated annual and peak demands of 1980, a reserve at that time of at least 500 MMMcf. will be required. Hence there must be added prior to 1960 a reserve of at least 500 MMMcf. to carry the operation until Leduc gas cap gas becomes available.

7. Market requirements have been estimated for gas having a heating value equivalent to Kinsella gas, about 960 B.T.U.'s per cubic feet. Leduc oil well gas is reported to run about 1,200 B.T.U.'s per cubic foot. Since the quantity of this gas to be available annually cannot be presently estimated with accuracy, and because most of the Leduc gas will become available only after 20 years, the preceding conclusion made no allowance for the higher B.T.U. quality of the Leduc gas, except in the conclusion "Hence there must be added prior to 1960 a reserve of at least 500 MMMcf." Were the Leduc gas of less than 1,000 B.T.U. quality, a greater addition to reserve would of course be needed.

Q Have you any comment on that map on the next page, that is, the map of the Northwestern system?

A That map shown here as page 10 indicates by a dash line the outline of the field that I have considered to be the proven commercial field. I present it now as representing that, and I used that a year or two ago in my last previous study when the field was then being, I would say, carefully studied in connection with the proposed purchase of the holdings in the field of the Imperial Oil Company.

Q You advised on that?

A I did advise on that, yes, sir.

Q Page 11.

A May I suggest, Mr. Steer, that inasmuch as I have referred in my discussions to the gas requirements of Northwestern and in one place state that I use an estimate of the reserves of Leduc, it might be well now to point out that the estimate of Leduc gas reserves as presented herein is part of the Northwestern studies.

Q Well then, perhaps we had better go to that.

A I was only saying that it can be brought in later after I have discussed Canadian Western.

Q Perhaps it will be more logical to go to that now.

A That is presented on pages 14 to 19 inclusive.

Q Yes, commencing at page 14?

A Yes, sir.

LEDUC-WOODBEND GAS RESERVES

by
Ralph E. Davis
Assisted by R.G. Paterson and A.E. Potter.

The two gentlemen named are engineers with the Canadian Western and Northwestern Utility Companies and they did assist me very greatly in the preparation of all basic data used in this study.

The purpose of present studies of the natural gas supply that may be reasonably expected in future years from the Leduc-Woodbend field lies in the importance of this supply to the markets supplied by Northwestern Utilities, Limited.

It has not been considered essential at this

time to make a detailed check of all factors that must be taken into account in making a gas reserve estimate, as certain of these basic factors will become better known with further development of the field and after a further production history. This is especially true of the D-2 zone and of the minor gas accumulations in the Cretaceous.

The study and resulting estimate herein presented is to be regarded as preliminary and the conclusions as approximations. For convenience the name "Leduc" will herein be used to refer to the combined Leduc-Woodbend fields.

Natural gas is recognized as present in commercial amounts in the gas cap and in the oil in the D-3 zone, in the oil in the D-2 zone, and in minor and probably relatively negligible amounts in both the Lower Cretaceous and the Viking sand horizons in limited areas in the field. In this study the last two are ignored as inconsequential at this time. The reserves in the other three categories are reviewed.

Studies of these reserves have been made by a number of authorities. I have found it convenient to review the published work of Dr. Hume, also the study of Devonian reserves made by Mr. James E. Baugh, as published in the June 23, 1949, issue of "The Oil and Gas Journal" and in the July 1950 issue of "Canadian Oil and Gas Industries". Independently a study of the more important D-3 zone has been made, at my request, by Mr. R.G. Paterson, Production Engineer of the Canadian Western and Northwestern Utilities companies, and is used by me

Ralph E. Davis,
Dir. Ex. by Mr. Steer.

in judging the reserves of this reservoir.

There follows the detail of that work, Mr. Steer. It can be read into the record.

THE CHAIRMAN: I do not think it is necessary.

MR. STEER: You think not, sir?

THE CHAIRMAN: No, I do not think so.

THE WITNESS:

D-3 Zone Gas Cap Reserves

Proven area (planimetered)	Main field	13,149	acres
	Okalta dome	490	"
	Ross Pet.	0	"
	Pan West	100	"
	TOTAL	13,739	acres

Average pay thickness (planimetered) 65.5 feet

Acre-feet,	900,000
Porosity (Imperial Oil)	13%
Connate Water (Imperial Oil)	12%
Original bottom hole Pressure (Imperial)	1894 psig
Bottom hole temperature	152°F.
Compressibility factor, Z, original,	0.817
Compressibility factor at 300 psi bottom hole abandonment pressure,	0.950

Gas per acre-foot - original

$$43560 \times .13 \times .88 \times \frac{1908}{14.4} \times \frac{520}{612} \times \frac{1}{0.817} = 687,000 \text{ c.f.}$$

Gas per acre-foot at 300 psig bottom hole pressure abandonment.

$$43560 \times .13 \times .88 \times \frac{314}{14.4} \times \frac{520}{612} \times \frac{1}{0.950} = 97,000 \text{ c.f.}$$

Producible gas per acre-foot = 687,000 - 97,000 = 590,000 c.f.

Total producible gas from gas cap = 590,000 x 900,000
= 531 MMMcf.

D-3 Zone Solution Gas Reserves

Assuming 50% oil recovery (regarded by me as probably being a high estimate)

Gas in solution at original conditions,	779 c.f./bbl Stock tank oil	
	534 c.f./bbl Reservoir fluid	
Gas in solution at 300 psig BHP abandonment,	261 c.f./bbl Stock tank oil	
	179 c.f./bbl Reservoir fluid	

Shrinkage at original conditions	0.685
Shrinkage at 300 psig BHP abandonment	0.814
Other data as used in gas cap estimate	

Proven area (planimetered)	Main reef	17,705
	Okalta dome	635
	Ross Pete dome	54
	Pan West dome	330
	TOTAL	18,724
Average pay thickness,		32.5 feet
Acre-feet		609,226

Effective pore space, = 7758 x .13 x .88
= 890 bbls/acre-foot

Stock tank oil in place, = 890 x 0.685
= 610 bbls/acre-foot

Total stock tank oil in place place, 372,000,000 bbls.

Original gas in solution, = 610 x 779
= 475,000 c.f./acre-foot

Gas remaining in solution at 300 psig BHP abandonment and 50% oil recovery, = 50% x 610 x 261
= 79,600 c.f./acre foot

Gas left in voided space

$$= 890\left(1 - \frac{0.5 \times 0.685}{0.814}\right)5.6 \times \frac{314}{14.4} \times \frac{520}{612} \times \frac{1}{0.950}$$

= 56,000 c.f./acre-foot

Producible gas = 475,000 - (79,600 + 56,000)
= 339,000 c.f./acre-foot

Total producible gas from oil zone, = 339,000 x 609,226
= 206 MMMcf.

Total producible gas from gas cap, 531 MMMcf.

Total producible gas from D-3 zone, 737 MMMcf.

It is not to be expected that all of the producible gas will be available for use outside of the field.

Before doing that I would like to summarize the final figures in which I state that the total producible gas from the oil zone in the D-3 horizon is 206 billion cubic feet according to this estimate, and the total producible gas from the gas cap is 531 billion, making a total producible gas of 737 billion, producible at the well heads.

The gas from the oil zone will experience removal of recoverable liquids, use and wastage in the field, and I estimate that about 60%, or say 124 MMMcf. will be available for pipe lines. That is, the oil field gas, gas from the oil zone. The recovery of gas cap gas, after the allowance already made for gas left in the reservoir, should be very high. Removal of liquids and losses should permit delivery of about 90%. At this time it is fair to assume that 90%, or 478 MMMcf. of this gas will become available to pipe lines. The total estimate of gas available from the D-3 zone to pipe lines is 602 MMMcf.

D-2 Zone

The D-2 zone is described by Baugh as having irregularly distributed porosity estimated by him to average 30 feet in thickness, 9% porosity, 15% connate water, and permeabilities much lower than prevalent in the D-3 reservoir. No gas cap is present, and water drive is extremely unlikely. Under these conditions a recovery of 20% is considered a reasonable expectancy. That is 20%

of the oil. At this time we may consider that about 15,000 acres have been proven. These assumptions form the basis of the following estimate. A careful detailed analysis involving a look at the records of every well is not justified by the purpose of this study.

And then there follows the arithmetic which I presume you will not ask me to read into the record.

Q That is right.

A Leduc D-2

Assume 15,000 acres having equivalent of 30 feet pay of 9% porosity and 15% connate water.
Assume 300 psig BHP abandonment.
Assume 20% recovery
Assume 9% porosity

Assume connate water 15%

Gas in solution - original conditions	718 c.f./bbl	Stock tank oil
Gas in solution - abandonment conditions	253 c.f./bbl	Stock tank oil
Z - 300 psig		0.951
Shrinkage (original conditions)		0.682
(abandonment)		0.796
Reservoir temp.		149°

Effective pore space $= \frac{43,560 \times .09 \times .85}{5.61} = 595$ bbls/acre-foot

Oil in place = 595 x 0.682 = 406 bbls. S.T.O./acre-foot

Total Stock tank oil in place = 183,000,000 bbls.

Gas in solution at original conditions
= 406 x 718 = 291,000 c.f./acre-foot

Oil left in reservoir = 80% x 406 bbls S.T.O./acre foot
Gas remaining in solution
= 253 x .80 x 406 = 82,200 c.f./acre foot

Evacuated void space $= 595 \left(1 - \frac{.80 \times 0.682}{0.796}\right)$ bbls/acre-foot

Unrecoverable gas in balance of void space

$$= \left(595 - \frac{.80 \times 406}{0.796}\right) 5.615 \times \frac{314}{14.4} \times \frac{520}{609} \times \frac{1}{0.951}$$

= 20.600 c.f./acre foot.

Producible gas = 291,000 - (82,200 ⁄ 20,600)
= 188,000 c.f./acre-foot
15,000 acres x 30 feet = 450,000 acre-feet
188,000 x 450,000 = 84 MMMcf producible gas

Estimated gas available to pipe lines at 60% of that producible = 50 MMMcf.

Summary of Leduc Gas Reserves
(Billions Cubic Feet)

Reservoir	Gas in Place	Gas Producible	Gas Available to Pipe Lines
D-3 Gas cap	618	531	478
D-3 Oil zone	289	206	124
D-2 Oil zone	131	84	50
TOTALS	1038	821	652
Field Devonian gas production to January 1, 1950,			42 *
Total available to pipe lines as of January 1, 1950,			610

* Includes a figure of approximately 35 MMMcf for Atlantic No. 3 blow-out.

And as I have stated, it is based to a great degree upon the reports of this Mr. Baugh who had very close contact with the detailed development of the Leduc field, and I have a high regard for his ability to do careful work. That is my reason for accepting his statements with regard to the detail.

Total available to pipelines from this oil field gas in the D-2 zone is taken at 60% of the total that we estimate will be produced. The gas that will be produced is placed at 84 billion and 60% of that would be 60 billion. Now, I will summarize the proven available gas from the Leduc field as presently estimated by me and my associates and in the light of present developments. The gas in place in the gas cap of the D-3 zone, 618

billion, of which 531 billion will be, I believe, producible and of which 478 billion will be available to pipe lines. Gas from the D-3 oil zone in place 289 billion, producible 206 billion, available to pipe lines 124 billion. From the D-2 oil zone reservoir, in place 131 billion, producible 84 billion, available to pipe lines 50 billion, giving a total of 652 billion available, and from that I deduct the gas that has been produced up to January 1st, 1950, which figure, 42 billion, is an estimate. It includes the estimated gas that was lost from the wild cat well that blew out up there, the Atlantic No. 3. Whether that estimated figure was high or low, it is the best I can arrive at, and even if it be off as much as 20 or 40 per cent it would not make any great difference in the final conclusion.

Q DR. GOVIER: Mr. Davis, is that figure your estimate or have you accepted someone else's estimate there?

A Certainly it was not my estimate. I found in my reading I think Mr. Baugh gave an estimate of total gas lost in that Atlantic Well of 25 billion. We had a record of gas used, taken from the reservoir in addition to that, for drilling wells and other purposes or blown to the air, and the combined figures came to 42, so it is an estimate made by Mr. Baugh, I believe Mr. Baugh, of the gas lost in the blow-out and the other figures are, I believe, available from records of the Conservation Board. I have just stated that that was 25 billion from the Atlantic No. 3. 25, that is the figure I carried in my mind. I

see here it is printed 35 and I would be glad to check that and tell you which figure is correct at a later time.

Q Well, it is 35 you have used in your report, Mr. Davis, in any case.

A I am only wondering if this be a typographical error, whether it is 25 plus 17 or 35 plus 7. I am not so sure.

Availability of Leduc Gas

It is generally conceded that the gas cap should be conserved until late in the period of oil production. Emergency uses of this gas might well be permitted for peak day deliveries for short time periods - - if this should become necessary. But generally speaking, the gas cap gas should be conserved during the period of major oil production. This means that this gas may not become available for 20 or 30 years.

The oil zone gas will be produced with the oil, and the demand for oil will be the controlling factor. Production of wet gas for the month of August 1950 was of the order of 18 million cubic feet per day, of which about 12 million went to the Imperial gasoline plant, yielding a stream of about 10 million cubic feet daily of stripped gas available to market use. This may be expected to increase somewhat, and Northwestern Utilities is preparing to handle the gas thus available.

Q MR. STEER: Then go back to page 11 considering Canadian Western.

THE CHAIRMAN: This might be an opportune time to recess.

(The Hearing then took a short recess.)

THE CHAIRMAN: Mr.Steer,do you intend to have Mr. Davis present the other reports here dealing with the Viking-Kinsella gas field reserves?

MR. STEER: Yes, that was our intention.

THE CHAIRMAN: That will go in later? Mr.Davis will go into that later?

MR. STEER: Yes, sir.

Q Mr.Davis, you might then proceed at page 11?

A

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

The gas deliveries of Canadian Western have been rapidly increasing during recent years. Expected requirements annually through 1980 have been estimated by the Company, as shown herewith, and the estimate is accepted by me in the study of the problem of gas supply to meet this need.

In January of this year a study was made of the sources of gas supply to Canadian Western. This study has been reviewed in the light of current information. The original report is submitted as a part of this report, with such additional information as is available, and with certain modified conclusions as expressed in the following statements.

Turner Valley

The basic source of gas to Canadian Western has since 1924 been the Turner Valley field. Total deliveries to Canadian Western in 1949 totalled 18,894 MMCF for system requirements, in addition to 658 MMCF taken to Bow Island for storage.

The table shown on Page 14 of the report referred to,

reflected an analysis of gas required from Turner Valley through 1960, to meet the market requirements as then estimated, and assuming no other basic source of gas. Bow Island and Foremost fields were assumed to fulfil the role assigned to them for many years, - that of supplying a part of peak requirements.

I would like to interpolate a statement here. I am describing here the study made in January of this year where we were dealing with the problem confronting the company before they made a contract with Shell for gas from Jumping Pound, so the report as then prepared presented the picture as I saw it at that time. It becomes necessary to modify those conclusions in the light of the new gas supply from Jumping Pound.

Since the acquisition of a gas supply at Jumping Pound, a revision of the above table is necessary. This has been prepared and is attached hereto. It will be noted that the supply of Turner Valley oil field gas is now estimated at a total of 172 MMCF during the period 1950-1960, that is the gross gas to be produced with the oil, after which time I now expect this source to supply only minor amounts of gas.

The supply from Jumping Pound is based upon the expectation that the field and facilities for gasproduction will enable the taking of gas in the amounts shown on the table.

The balance of the supply will come from the gas cap at Turner Valley, except for minor amounts of peak day gas from Foremost. Bow Island will continue as a storage field, - annual input to equal output if possible. It

is assumed that the annual turnover in Bow Island will average 1000 MMCF during the period.

Jumping Pound.

The reserve estimates of Jumping Pound as presented in the attached report are made a part of this study. The only information available to me regarding deliverability is the reported initial open flow of the two completed wells and the back pressure-potential tests made by Shell, and available elsewhere in the records of the Commission. I believe that the average well will produce gas sufficient to put at least an average of 5 MMCF of gas daily into the pipe line, after scrubbing and plant losses. Upon this basis I have estimated annual deliveries of from 5.8 MMMCF in 1951 to 17.9 MMMCF in 1960.

Summary

The total reserves available to Canadian Western are estimated by me at January 1, 1950, as follows:

Field	Raw Gas	Pipe Line Gas
	(Billions Cubic Feet)	
Turner Valley Gas Cap	350	280

We have not included 7 billion to other markets in Turner Valley and vicinity not delivered to Canadian Western.

Oil Field	172	80
Jumping Pound	535	400
Bow Island	15	15

Most of that Bow Island gas is gas that has been returned to the reservoir. It is sweet gas, and will require no treatment when taken.

Foremost	15	15

That is the estimated reserves at Foremost and as shown

in the other report that I am making a part of this study, so that I have a total pipe line gas available to Canadian Western of 790 billion cubic feet.

The total estimated requirements for the period 1950-1960, 11 years, is 307 MMMCF; for the period 1961-1970, 10 years, the estimate calls for 353 MMMcf. For the period 1971-1980, 10 years, the estimate calls for 404 MMMCF. The total for 31 years is 1064 MMMCF.

Conclusions

1. It is evident that the present sources of supply will be inadequate to meet the system requirements for more than about 10 or 12 years. The total reserve of 790 MMMCF is short by 274 MMMCF of the quantity needed for 31 years.

2. To meet estimated peak requirements in1980, it will be necessary at that time to have a reserve of at least 500 MMMCF.

If that conclusion be not clear, I will say that to meet the peak flow of gas required it requires wells with sufficient pressure and with sufficient reserves to produce the needed quantity and I would think that 500 billion would be a minimum.

3. There must be added to the system reserves at least 750 MMMCF to carry the operation through 1980. This additional reserve should be acquired within the next 10 years if possible.

MR. STEER: Now, Mr.Davis, in the course of this report you have referred to the percentage of gas in a reservoir that is recoverable?

A Yes.

Q Would you relate to the Board the methods that you used in making those calculations?

A I will be glad to do that. In connection with other studies I have made a comprehensive study of as many depleted or nearly depleted gas fields, choosing fields that were not oil and gas fields but rather non-associated gas fields, I have searched the country for fields of that type that have been depleted or nearly depleted, fields where we have a good record of the total production to date and have the amount taken in each year of the fields' productive history, fields where it was possible to arrive at a close approximation of the total gas in the reservoir having, for our basic data, the total past production, the annual decline in pressure and any related data that might be useful, and from the study of 36 of these fields, 24 were found in the Texas and Louisiana Gulf Coast territory, the other 12 being in fields, 2 in California, 2 in Michigan, 1 in Wyoming, 1 in Oklahoma, 2, I believe, in Ohio, 1 in West Virginia, 1 in Southwestern New York. I do not know if that would add up to 12, but there were 12 fields outside of those found in the Gulf Coast country, and after making the study, or studies that were necessary, I found that the total production of these fields averaged 87% of the total estimated original reserves in the reservoir. I think it proper to conclude that generally we may expect from an average field to recover somewhere between 85 and 90% of its reserves. In some places I am sure we recovered more than 90%, and in some I am sure we recovered less than 80%. Fields of high permeability, high initial

pressures, fields from which the gas is easily obtained, and fields in which we sometimes have a water-drive to push the gas out, there you would get 90 to 95% recovery. Fields where the formation is tight, of low permeability, where the reserves are of a low amount per acre, and economy requires wells to be somewhat widely spaced, in wells of that type the recovery is apt to be 80% oreven less.

Now, it is such a custom in the industry, and among people who estimate reserves, to say or assume that the gas will be taken to an abandonment pressure average at the well head of so many pounds per square inch gauge pressure. I did that myself for many years before I found it convenient to apply this later method. I still continue in making reports to frequently say,"I assume an abandonment pressure, that the gas will be taken to such a pressure", and in Kinsella that abandonment pressure which I named is 200 pounds per square inch average well head pressure, gauge pressure. But I always test that figure today by seeing what that will amount in terms of percentage of total gas withdrawn, and if the two be in essential agreement then I am happy to use it in one way or the other. I would also say that I think it equally difficult to determine an abandonment pressure many years in advance of that final abandonment, or to find a percentage of total recovery many, many years in advance of final abandonment. We have to judge these things on the basis of experience from many fields. And so I present to this Board that analysis of my presentation.

Q I understand that if the Board would desire that you have

available the records of your examination of these 36 fields?

A Yes, sir.

Q From that point of view?

A Yes, I have with me graphic records of the 36 fields which I have just referred to. They show the production of the field, they show the quantity of gas, the percentage of the total at the time of abandonment, they show the gas taken in each year as a percentage of the total gas, and it might be interesting to make one further statement regarding that study, that not only do I find by this what seems to me to be a fair assumption as to the total gas that will be recovered, but we find the rate at which recovery may be expected during the later years of a field's productive history. So that instead of undertaking to find what the deliverability will be from a field, let us say, in 1975, we first estimate the total gas in place, second, estimate how much gas will have been taken out prior to '75, estimate how much gas will be needed in '75, estimate by the use of back pressure potential graphs how much gas can then be obtained from an individual well, and then from that stepping out and estimating how many wells will be required. I find it convenient to consider the first thing I named, the total gas estimated to be in place, and I find from a study of these fields just about what percentage of the total gas in place can be taken when the field begins its physical decline at about 65% depletion, and the percentage of the gas I can expect to get in one year when the depletion has reached 65, 70, 75, 80 or 85%. And the results obtained by first working

out those 24 fields in the Gulf Coast, I had those figures available to me as I worked that out, and then I sought to check that by taking fields from various parts of the country, and when I had found an additional 12 fields that I could use, and made a similar study, I had figures that checked very closely, one group against the other group, and I would be glad to present the Board with the basic data that I used in connection with this study, if they have any desire that I do so.

THE CHAIRMAN: You might enter that as Exhibit Number J-4.

BASIC DATA USED IN STUDY BY MR. R. E. DAVIS RE 36 FIELDS MARKED EXHIBIT J-4.

Q MR. STEER: I am afraid we cannot supply copies of those, can we, Mr. Davis?

A There are 36 graphs here, and I have a few, several of them. I would like to see that the Brokaw, Dixon & McKee people have a set, they are old friends of mine. If there is any other party in the Hearing that would particularly desire to have a set, I can arrange it.

Q You had better arrange for all of them because they are all friends of yours?

A I did not put it on that basis. I meant people who needed them. I think you would like to have a set, Mr. McDonald?

MR. McDONALD: Yes, I would like to have one.

A I was picking you out.

Q MR. STEER: Well, I have here similar studies that were made under your direction, I believe, with regard to Bow Island and Chin Coulee?

A Yes.

Q Depleted fields?

A Yes, it was suggested that inasmuch as I had found what happened in 36 fields, why not find out what happened in two of our Alberta fields that are essentially depleted. And so the data from Bow Island has been reduced into graphic form, and I have a number of copies of that. Incidetnally, Bow Island shows essential depletion after recovery of 82½% of the gas in place. The Barnwell gas field, a very small field, indicates a recovery during its production history of only 72% of the gas in place. We have those variations.

Q What would that be due to, 72% only?

A I think it is, Mr. Steer, - I don't know, I wasn't there. However, the total gas in that reservoir was estimated at 2 billion feet and they operated that field for two, three, four, five, six, seven, eight, nine, ten, eleven years, and they finally were getting out the next to the last year, in that year they only took 1% of the total gas in place, and I think it was time to stop. It wasn't economic to keep on pulling gas. They might have got some more if they tried.

Q What I gather from what you have to say is that that would be due to very low porosity and very low quantity of gas per acre, am I right in that?

A No, I do not believe that is right. I do not know the field, but this Barnwell field, during the second and third years, produced in each year more than 20% of the total gas in place. That does not sound like awfully tight rock. It just sounds like to me, like an awfully small field.

MR. STEER: Well, perhaps we had better file

those, sir.

Q THE CHAIRMAN: Are they together or separate ones for each group?

A They are in one little group.

Q All right. We will mark that Exhibit J-5.

GRAPHS RELATING TO BOW ISLAND AND BARNWELL FIELDS MARKED EXHIBIT J-5.

Q DR. GOVIER: Mr. Davis, could I ask you a question while it is fresh in my mind?

A Yes.

Q Did you take the deliverability versus present production of the Bow Island and this other field against your generalized curve based on your study of the 36 fields in the United States?

A Well, I could do it right now. I did not, but I could do that. There is nothing to it.

Q If you would?

A It will just take a moment, and we will see what we get.

Q I don't mean so much on the total volume recovered as I did on the deliverability aspect of it?

A Well, in my generalized study I find that in my 24 fields of the Gulf Coast I can expect to take 5% of the total gas even when the field has been 75% depleted.

Q Yes?

Q MR. STEER: That is 5% of the total gas annually?

A Yes, in one year. I will come up to 75% of the Bow Island curve, and I will tell you that in that year they did take 3%.

Q DR. GOVIER: And what about the other field?

A I do not like to talk about the other field. The other

field was able to produce 5% of its gas when it has reached a depletion of 65%.

Q How much did it produce at 75% depletion?

A It never got that far. It ended at 72.

Q 72?

A Yes.

Q MR. STEER: Would you have used the Barnwell field in making this general study of yours if you had come across it in the United States?

A Yes, I would. I would have used any field where I had complete data. I wanted a complete cross-picture. I did not eliminate any field on the ground that I did not like it. I eliminated fields where my data was questionable, where I either did not have good production history, or something of that kind.

Q DR. GOVIER: What I was wondering about, Mr.Davis, was this, would you put more weight on a generalized study or on an individual field study, assuming you had some reasonable data on the field?

A Well, you want to be specific, I presume?

Q All right, let us talk about Viking-Kinsella then?

A All right, Viking-Kinsella. We have up there something like 70 wells, I believe. It is anticipated that we will need 150, more or less, something of that order. Now, I believe that I will be just as close to arrive at what the deliverability will be in 1965 by using my generalized approach as the man will be who has found the average back pressure potential on the present 44 wells that he is testing, and then makes a calculation of what the back pressure potential is going to be on the 80 or 90 wells that are not yet

drilled. I think there are many uncertainties that attach, let us say, to either method. I believe this generalized method of mine is the better of the two, generally speaking. Any method can go wrong in any particular field. I would rather have Jumping Pound where you have two wells, where I have made an estimate of reserves, I would rather base an expectancy of what amount of gas can be taken out of it in, say, 1970, on my generalized picture than on an estimate made by one who says, "We are going to need 10 wells or 12 wells, and those wells are going to be 35 million back pressure potential each". I think there is just as much guesswork in that detailed method, so to speak, as there is in my method.

I might tell you that I had all of the data which had been presented to the Federal Power Commission, it is open to the public,and the back pressure potential estimates made by Tennessee Company, they have 83 fields from which they take gas, and I applied this short cut of mine to 64 of those fields, and there were 24 fields where my approach gave me more, and there were 40 fields where my approach gave me less, but the whole, generally, averaged out pretty close, and the reason I did not apply it to all 83 fields was this, with regard to some of the fields we did not have the basic data.

Q I take it, Mr.Davis, that the 36 fields you have included in those fields of various types, either gas fields, condensate fields, quite a wide variety included in that, is that right?

A I tried to stick to dry gas fields, but in every dry gas field, with the exception of a few, Kinsella is an exception, we

have more or less liquid, recoverable liquid, and I accepted the field even though it had a condensate recovery, but I did not use fields where the gas was in part oil field gas.

Q I see. But there would have been fields of the general type of Jumping Pound and Pincher Creek included, would there?

A Yes. I did not have, I do not believe I had a field, I know I did not have a field of such enormous depth, and, therefore, such enormous pressures. I do not know of any field down in the States where I went where a field of that depth has been depleted, so that I could use it, but I was looking at fields of great depth most of the time. In all these fields were fields from pressures of 700 to 1200 pounds, and I wanted to find out or find a field with 2000, 3000 or 4000 pound pressures, and they are hard to find. I did have some, and just because they are 4000 pound fields does not seem to throw them out of line for the average of the others.

(Go to Page 56).

Q Just one more question and I will turn you back to Mr. Steer. Has there been enough production from the Viking-Kinsella to take its current per cent depletion and its current deliverability and check that with your generalized study?

A I cannot check it. I can tell you what I think the answer is going to be. I cannot check it against a field like Bow Island where I have a depletion, say, to an end point or near an end point.

Q You could check it against your estimate of gas in place couldn't you?

A I could take Kinsella where I say the present recoverable reserves are in the order of 612 billion. We have only taken out of the field 130 billion. We are only 20 per cent depleted, in round figures. In other words, Kinsella is in the early part of its total production history and I cannot do anything with Kinsella except to say this measuring stick that I developed with the 36 fields, and I will apply it to Kinsella and tell you what I think will happen there. I cannot say that Kinsella, with its present state of production, would prove my point.

Q The present depletion of Kinsella is, did you say, about 132 out of six hundred and something?

A I say the remaining reserve up to 200 pounds is 612 billion. Past production is 130 billion, so that there will be 342 billions and that is gas recoverable down to an abandonment of 200 pounds at the well head. I think the total gas in place in Kinsella - I have that figure, my estimate of it - it was 900 on the volumetric method basis estimate which was made in September, 1948. I made an estimate of the Kinsella

field at that time by volumetric method, finding the average sand thickness and taking into account porosity, connate water and area and I figured at that time initial gas in place 960 billion. And at the same time an estimate was made by the pressure decline method at 996.5. The lower of these estimates indicated - I ran this out recently - that at December 31st, 1950, the remaining reserves by the first method, I figured, 585 billion and by the pressure decline method it would be 612. I choose to use the 612, my reason being that in my volumetric method I ignored any gas that might slowly migrate into the area outlined as the productive area from adjoining areas, where the sand is thin, 1 foot thick or 2 feet thick maybe, but this gas at 750 pounds pressure, top of the well pressure, the gas will move into that productive area from outside my present areas. The extent of that is not likely to be marked as compared with the total within the field, so I just used the higher estimate. I have been wondering during the last few weeks, since I commenced on this present study, whether or not I have been too generous with Kinsella. At the beginning of this current year Northwestern Utilities planned to drill 6 wells to have a sufficient supply for the coming winter, and after drilling the 6 wells they were disappointed in the capacity and the production of those wells. As a result, they drilled two more wells this year than had been planned. In other words, I would take it from this you should not take any figure higher than I have given you. Of two wells, one well has been abandoned on account of water within the last year. It is a surprise to me that

has been the case and another well recently put on the line and expected to be a good producer is already making a notable amount of water. So I say that you had best not regard the Kinsella reserves as being in excess of about 600 billion.

Q I think I got a little lost there. Is this right, that one of your estimates of original gas in place at Viking-Kinsella was about 1 trillion?

A 996.5 billion.

Q And that your estimate of residual gas in place is .6 trillion. Is that right?

A Oh, no.

Q I thought you said 612 billion?

A All right, I say this, let us take my pressure decline reserve study. The total gas in place initially was 996 billion. Recoverable reserves, January 1st, 1950, 612½ billion.

Q Can you tell me this, Mr. Davis, your estimate of the per cent of original gas in place which has been produced at the Viking-Kinsella?

A Yes, sir, we have produced 130 billion and I figured 996 in place so I have produced 13 per cent.

Q Does your generalized correlation come down as low as 13 per cent? Or to put it again, does your generalized correlation indicate the annual withdrawal which one might expect for a field which has had only 13 per cent depletion?

A My generalized study is based upon fields which have had generally, as nearly as possible, 100 per cent of the total recoverable gas taken. I would never, I could not use

Kinsella as one of my 36 fields.

Q I appreciate that. But my understanding of your study was that it included, or it indicated the percentage that might be withdrawn per year from fields at various stages in their depletion life?

A That is right. In the final stages of their depletion life.

Q Is it only in the final stages?

A I could have done it for the intervening stages but it would have meant nothing, to my way of looking at it. Now, let us take a field like the Munro Gas Field. That field produced, I think, about 5 trillion feet of gas. More than 5 trillion. The total gas in reservoir initially, as believed by most of us, approximated 6½ trillion. There was never a year in which the market and the facilities for handling the gas could handle more than 4 per cent of the total reserves in that field. The field was so large that when they got that 4 per cent of 6 trillion, they were taking all the gas that the market wanted.

Q Your answer to my question is that your studies do not include a depletion as low as this. Is that right? That is 13 per cent?

A That is right.

Q That is fine. That is all I want.

Q MR. STEER: Now, on page 11 of this exhibit J-2, Mr. Davis, you referred to a study of January 1950. You have a copy of that in this grey folder, have you?

A I have it, sir.

MR. STEER: If the Board pleases, I will have

Mr. Davis give that report to the Board.

REPORT NOW MARKED
EXHIBIT J-6.

A You are referring to the report on the Gas Supply as of January 1, 1950 and dated April 28th, 1950?

Q That is right.

A Please do not make me read all that.

Q That is what you are being paid for.

A During the intermission I was told some of the people did not want to listen to so much.

Q You can start on page 1.

A I did not know that the Board would ask me to read this.

Q Oh, yes.

A This report presents the results of a study of the natural gas situation of the Canadian Western Natural Gas Company, Limited. The Company obtains the major portion of its natural gas through purchase at Turner Valley, this gas being produced, gathered, compressed, and treated for removal of liquid hydrocarbons and sulphur compounds by non-affiliated companies. Canadian Western also produces gas in the Foremost and Bow Island gas fields to supplement the purchases from Turner Valley during periods of peak demand. The markets served include Calgary, Lethbridge, Macleod and other small towns. The largest industrial customers are the Alberta Nitrogen plant and the Imperial Refinery, both located in, or near, Calgary.

<u>History of the Company's Gas Supply</u>

The Canadian Western Natural Gas Company, Limited, through its predecessor company, Canadian Western Natural Gas, Light, Heat & Power Company, Limited, began supplying

natural gas to Calgary, Macleod and several small towns in 1912. The Bow Island field in southeastern Alberta was connected with the Calgary market with a 16" line 168 miles long. The gas requirements of the System amounted to 2.05 billion cubic feet in 1924. During the years prior to 1925 the Bow Island field had been substantially depleted. The reserves of the Company had, however, been augmented by its discovery of the Foremost field, situated about 38 miles south of the Bow Island field. In 1924 the first well, Royalite No. 4, to be drilled to the Mississippian Lime in the Turner Valley field was completed. The production characteristics of this well, and the known geologic character of the Turner Valley structure, revealed the presence of a gas supply of enormous proportions and of great importance to the Canadian Western Company and the markets served by it. A contract was entered into in 1925 between the Canadian Western Company as purchaser and the Royalite Oil Company as seller, which in 1925 I regarded as assuring the Canadian Western Company a competent gas supply for many years.

During the years that have followed 1925, the Turner Valley field has been developed by the drilling of about 100 wells in the natural gas (gas cap) portion of the field, proving it to embrace a productive area of some 10,000 acres, and by the completion of 311 oil wells productive from the Mississippian Lime along the western down dip flank of the structure. Development of the oil area is now regarded as practically complete. The presently proven productive oil area embraces approximately 15,000

acres.

The total gas production from the gas cap wells has probably exceeded 1,100 billion cubic feet. Much of this gas was blown to the air (burned) after the extraction from it of natural gasoline and naphtha. An effective conservation plan was established in 1942, and since that year gas from gas cap wells is produced only to the extent that markets can absorb it (except for unavoidable waste of minor proportions).

Oil production from the Mississippian Lime in Turner Valley began in 1936. To the end of 1949 a total of 85,297,330 barrels of oil had been produced, exclusive of 30,180 barrels of naphtha obtained in the separators of the gas cap wells. The peak production was experienced in 1942. Today, the total daily production is slightly in excess of 10,000 barrels.

During the past three years oil production has been

1947 ---------------------	5,006,153 barrels
1948 ---------------------	4,418,580 barrels
1949 ---------------------	3,816,064 barrels

The future oil production is likely to approximate 13,500,000 barrels. The extent of this oil production is of great importance in the matter of gas supply, and for this reason: the conservation of natural gas in Turner Valley embraces not only gas from the gas cap, but gas from the oil wells. The amount of gas produced with the oil is very considerable, and were it practical to gather and conserve all of it, the markets of Canadian Western and others could be supplied for several years without use

(except for about six colder weather months) of gas cap reserves or wells. It is not quite as simple as that, however. There is still a substantial loss of gas in the oil field due to the impracticability of gathering all gas produced. Furthermore, considerable amounts of gas are required for oil field operation.

In 1947, the oil field gas gathered, but not including that used as "Field Fuel, Plant Use, Shrinkage and Waste", amounted to 62 per cent of that produced, in 1948 the percentage gathered was 59 and in 1949 the percentage gathered was 56. Facilities in the north Turner Valley field have been inadequate for gathering the gas produced, thus increasing the loss of gas. It would not, in my judgment, be economically feasible in the future, except to a limited extent, to install additional gas gathering facilities. It is doubtful if we can expect an average future recovery of marketable gas exceeding 50 per cent of gross oil field gas production.

The oil field gas produced in 1949 amounted to 29,503,000 Mcf, of which 16,720,000 Mcf or approximately 56 per cent, became available for drilling fuel, market uses and storage. In the colder months, this gas is delivered to Canadian Western and others (including field users), and the gas cap wells supply whatever additional gas is needed to meet the market demand. In the summer months, the markets are similarly served, the excess gas gathered from the oil wells being pumped back into the gas cap reservoir, and a small part is transported and stored in the Bow Island field.

It has seemed necessary to present the foregoing brief history to make understandable the approach to the study of gas reserves and the availability thereof.

TURNER VALLEY OIL FIELD

Gas Reserves

Gas produced with oil is essential to the production of the oil. The gas is dissolved in the oil, and under the conditions existent in the oil reservoir before production began, each barrel of oil carried approximately 600 cubic feet of natural gas. Upon the completion of a well, the pressure in the oil reservoir near the well bore is reduced, permitting the dissolved gas to expand and partially to escape as bubbles of free gas. Some of this gas escapes to the well, causing oil to also escape, and where the volume of gas is sufficient and pressures are sufficient (as is presently the case in Turner Valley), the escaping gas stream carries the oil to the surface. The gas that escapes includes that which was dissolved in the oil produced, also a part of the gas dissolved in a much greater amount of oil that remains underground. The gas that escapes through the oil wells is only a part of that released from solution, the remainder slowly migrating up structure where it may eventually become a part of the gas cap gas.

The problem of estimating the quantity of gas that will be released through oil wells resolves itself into the following procedure:

1. Estimate the future oil production by years.
2. Estimate the gas-oil ratio for each future year.

3. Based upon 1 and 2, estimated future annual gas production is readily determined.

As to the first of these, it is found that by grouping the oil wells into (a) wells in the south field completed prior to 1938, (b) wells of the south field completed in 1938, and (c-d-e-f-g-h-i and j) wells of the south field completed in each year since 1938, that the decline in production for each well group is orderly and forms a competent basis for estimating the oil production in each future year.

As to the second step, it is found that the gas-oil ratio (quantitative relation of gas production to oil production of the oil wells) for the wells of each year group has steadily increased since the first year of production, and this affords a reliable basis for estimating the gas-oil ratio for each future year.

It thus becomes apparent that if we have been able to estimate with fair accuracy both the oil production and the gas-oil ratio for each group of wells for, let us say, the year 1950, we have thereby arrived at a fair estimate of the gas production of these wells for 1950.

A similar procedure is followed in dealing with the north oil field. A factor of importance is met in the north field, not present in the south field. The south field is considered to be completely developed. It is probable that only one or two additional wells will be drilled in the north field, and it is necessary to take them into account. Oil production and gas-oil ratios for these undrilled wells are estimated on the basis of experience

with older wells.

To estimate the recoverable and usable gas that will be available from the total oil field gas production, it is essential to study the history of field waste, plant waste and losses due to shrinkage in removal of sulphur compounds, liquid hydrocarbons, water vapor, etc., and trends that may have developed. In 1941, the waste in the field and absorption plants and the plant shrinkage totaled 34 billion cubic feet. The nitrogen plant began using 10 million cubic feet daily in the latter part of 1941, thus absorbing that much gas that would otherwise have been wasted for a time at least. The introduction of an effective conservation program in the field brought about a decline in field wastage as shown in the following table:

Year	Field Waste	Plant Waste	Shrinkage & Plant Vapors	Total
1941	33.85 billion	Included in Field Waste	Included in Field Waste	33.85 billion
1942	23.99 billion	Included in Field Waste	Included in Field Waste	23.99 billion
1943	20.93 billion	Included in Field Waste	Included in Field Waste	20.93 billion
1944	14.73 billion	3.53 billion		18.26 billion
1945	6.49 billion	1.53 billion	2.22 billion	10.24 billion
1946	5.58 billion	.98 billion	2.36 billion	8.92 billion
1947	5.83 billion	0.41 billion	2.38 billion	8.62 billion
1948	6.62 billion	0.36 billion	2.35 billion	9.33 billion
1949	6.41 billion	0.10 billion	2.64 billion	9.15 billion

Conservation of gas produced in the oil field

became effective in 1945, and was in part accomplished by returning gas to the gas cap reservoir in Turner Valley and by storage in Bow Island the following quantities of gas.

The following table presents data relating to gas storage, 1945 to 1949, inclusive.

	Gas Stored (Mcf)	
Year	Turner Valley	Bow Island *
1945	3,000,000	637,842
1946	4,400,000	890,416
1947	3,730,000	808,598
1948	3,136,000	334,741
1949	2,050,000	630,710

* Does not include compressor fuel at Bow Island.

A total of 209 oil wells are now connected to the gas gathering system. These wells are delivering most of their gas production into the gathering system. As pressures decline, a point is reached where delivery of gas into the line is impossible unless line pressures are reduced. Some wells have reached this stage. Gas lift has been put into use in several wells. It is likely that an increasing number of connected wells will cease delivery of gas into the gathering system, and thus bring about decline in the gas available.

Gas Reserves of Oil Wells - Turner Valley Field.

The oil reserves, recoverable by present methods of operation and including possible use of gas lift in later stages of operation, are estimated by me at 13,500,000

barrels as of January 1, 1950. This estimate is based upon a study of past production and the rate of decline in production. An economic limit of 3,500 barrels per well per year is assumed for wells reaching that stage prior to 1960. No estimate of production after 1960 is made.

(Go to page 69.)

The gas-oil ratio for each future year is estimated, based upon the history of increase in this ratio during the past years. The rate of increase in the gas-oil ratio has been remarkably constant. A change in the regulations governing methods of production could and doubtless would affect the rate of increase, and in all probability permit the ratio to increase faster than in recent years. By adopting for future years an increase in the gas-oil ratio no greater than the average of recent years, gives, I believe, a conservative estimate of future gas production from the oil wells.

The estimated total gas production after January 1, 1950, of the Turner Valley oil wells during the life of their operation as oil, or oil and gas wells is 127 billion cubic feet. This is exclusive of gas that will be produced after reclassification from wells situated close to the gas cap after such wells have become reclassified as gas wells. This compares with a total past production of oil field gas (to December 31, 1949) of 361 billion cubic feet and with 1949 production of 29.5 billion cubic feet.

It is my belief that a goodly number of the oil wells, particularly those located along the up dip border of the oil area, will become gas wells in time. This has already occurred in the case of 34 wells, although only 12 of these have been officially reclassified by the Conservation Board. This is another way of saying that the gas cap is encroaching into the area of the oil field. Inasmuch as any gas production to be had from wells of this category will be gas taken from the enlarged gas cap

reservoir, it appears best to make allowance for this future production in handling the problem of reserves of the gas cap reservoir.

I meant by that last statement that gas that will be taken in future from the wells along the oil-gas border, wells that were oil wells but which will become gas wells, that that gas I will regard as gas cap production and should be included in gas cap estimates and eliminated from estimates made of oil wells production.

Turner Valley Gas Cap Reserves

The Turner Valley gas cap embraces approximately 10,000 acres. It occupies the crest of the structure, being limited on the northeast side by a major fault and on the west, or down-dip side, by the oil zone.

Gas was discovered in the limestone in 1924 by the Royalite #4. The gas had a high naphtha content and many wells were drilled for the sole purpose of recovering this naphtha with the residue gas being wasted. Records of gas production in the early years are not complete and it is believed that the recorded data do not reflect the total gas withdrawals. Only a relatively minor amount of the gas produced in those early years was marketed. As pressures in the gas cap decreased, the recovery of naphtha also decreased, making it less desirable to operate the wells for the sole purpose of obtaining this product. At the present time, essentially all of the gas produced from the gas cap is gathered and, after being treated, is available to the markets. Excess gas over the market

requirements (resulting from oil field production) is being stored in the gas cap at the present time.

As of January 1, 1950, there were about eighty-five wells located in the original gas cap area. In addition 34 former oil wells, an increase of 22 in three years, presently have gas-oil ratios exceeding 30 Mcf per barrel of oil and will produce from the enlarged gas cap. Some wells are used as input wells and gas is produced from some of the input wells during winter periods. The total production from the original gas cap is estimated at over 1,100 billion cubic feet to January 1, 1950, and possibly may exceed this figure by 300 to 400 billion cubic feet. During 1946, stored gas exceeded production by the amount of 372.5 million cubic feet, while during the period 1947-1949, withdrawals have exceeded input by nearly 11 billion cubic feet.

The initial rock pressure of the field was never gauged, but is believed to have been approximately 2,050 pounds per square inch gauge (top of well pressure).

The relationship between production and pressure is shown in tabular form on page 12 and graphically on page 15. On the graph, both arithmetic average pressures (top of well pressures) are areally weighted average pressures (also top-hole) are plotted against both time and production.

The problem of estimating gas cap reserves is complicated by several factors, e.g.:

(a) The actual gas production in early years is not known.

Ralph E. Davis,
Dir. Ex. by Mr. Steer.

(b) The degree of stabilization of pressure at the time the pressure readings were taken has doubtless varied from time to time. Pressures obtained in the early 1930's were taken at a time when the field was producing at a high rate and the wells were probably not shut in for a sufficient time to enable complete stabilization. In 1937, a portion of the gas cap (operated by Royalite) was partially conserved and a greater degree of stabilization would consequently be obtained thereafter. A further curtailment of gas production resulted from the introduction of the Brown plan in 1942, and the following period probably represents the nearest approach to a stabilized pressure since the development of the field. Late in 1944, the storage of gas in the gas cap was started.

(c) Gas released from solution in oil along the west edge of the gas cap has doubtless partially been migrating up-dip into the gas cap, thus sustaining pressures therein. The tendency for this to happen during the next few years will be lessened as the pressure in the gas cap is maintained by curtailment and storage of gas while the pressure in the oil zone continues to decrease as a result of continued production therefrom, thus decreasing the pressure differential between the two zones and retarding gas flow.

(d) The porous reservoir of the original gas cap may have decreased in volume during the early years of field operation due to the upward migration of oil under

the pressure differential resulting from large gas cap production. During recent years, the gas cap reservoir is undoubtedly increasing in size.

After giving due consideration to the above factors which have an effect on the quantity of gas available from the gas cap, it is concluded that future production therefrom, after January 1, 1950, will be of the order of 350 billion cubic feet of wet gas. This estimate assumes production to an average bottom hole pressure of 200 p.s.i.g. The increase in this estimate over the estimate of "over 300 billion cubic feet" made by me as of January 1, 1947, results I believe from addition to reserves as a result of upward migration from the oil zone. This migration of gas from the oil zone to the gas cap is expected to continue for a long time, and is likely to make necessary further upward revisions of reserve estimates in future years.

Summary - Total Wet Gas Reserves

The recoverable reserve of natural gas from the Turner Valley field as of January 1, 1950, is estimated at 477 billion cubic feet. This gas is wet, sour gas and not available to markets in the condition in which it exists at time of production. Of the total of 477 billion cubic feet estimated, it is considered that 350 billion cubic feet will be recovered from the gas cap and 127 billion cubic feet from the oil field.

Estimated Gas Available to Markets

The present conservation scheme dealing with the natural gas produced in Turner Valley became operative

about the first of 1945. A table is presented on page 13 showing in detail the disposition of the gas produced for the years 1945 to 1949 inclusive.

As the operating pressures on the oil wells decline, individual wells reach the point where gas from them will not enter the gathering system unless the operating pressure therein be lowered. It is not feasible to lower the gathering line pressure every time the well pressure becomes too low to feed, and it will thus be necessary to flare gas from individual wells until such time as a reduction of line pressures may be justified.

It is possible that there will be an increase in the use of gas for gas lift in the oil wells.

Based on recent experience, it is estimated that increasing percentages of the oil field gas will either be wasted, used in the field or be required for plant use and shrinkage. Such losses have increased from 37% to 42% in 1949 and further increase is expected. The overall percentage of oil well gas available for markets is placed at 50 per cent. In the case of the gas cap wells, it is estimated that 18 per cent will be required for plant use and shrinkage.

The total gas available from the Turner Valley field for markets is estimated as follows:

	Dry Gas Million Cubic Feet			
Gas Cap Gas	350,000	less 18% =	287,000	deliverable
Oil Field Gas	127,000	less 50% =	63,500	to be deliverable
Total	477,000	say	350,000	

The gas available for markets will be disposed of as follows:

(1) Used in Turner Valley for drilling fuel. Future insignificant.

(2) Domestic and industrial use in Turner Valley. Future very small.

(3) Markets served by Canadian Western.

It is assumed that the gas will all be available to the present markets.

The annual rate at which the gas from the field may be produced and become available is estimated as shown on page 14.

Now, there are several pages that I include in here, also graphs. Surely it would not add to anybody's understanding to have me read those pages.

Q I think not.

Q DR. GOVIER: Mr. Davis, would you be good enough to explain the note on the bottom of page 14.

A It has been eight months. How long ago did I write this?

MR. D.P. McDONALD: January 1st.

A It has been several months since I prepared this. The note says, "It is recognized that lack of facilities would preclude this program for so long a term." Now, that does not make sense. That is not correctly copied. I believe that it is not correctly copied. But the lack of facilities would make it impossible to take as much gas from the Turner Valley gas cap as is outlined on this table. This table presents the amount of gas that would have to come out of the gas cap to meet the market requirements up to

1960. If my estimate of the gas available from the oil zone is correct, if the gas available from Bow Island is only an annual trading of gas, if the gas from Foremost be nominal for peak loads, then this tabulation assumes that the balance of the gas required would have to come from the gas cap, and my note is placed there to explain that facilities are not present to permit so large an increase of gas cap gas. 1949 the gas cap wet gas produced 7,580,000,000 and by 1960 there would be required 35,500,000,000. That could not be done without new facilities in Turner Valley that are not feasible. This report, sir, was prepared back in the early part of this year in connection with studies of what is Canadian Western going to do. This was to show that we can not depend on Turner Valley.

Q DR. GOVIER: Well, Mr. Davis, what weight should we give to the final total figures on page 14? What do they really mean now?

A Well, I have given you in this most recent study, I think I have, I have given you on page 28 a tabulation comparable to that on page 14 in my first or earlier study, and on this tabulation on page 20 of Exhibit J-2 - -

MR. STEER: Yes, that is right.

A I would say that that is made in the light of information as of today.

Q DR. GOVIER: That really supersedes page 14?

A That is right. I believe that the figures presented on this tabulation as, for example, gas from the gas cap, that would be required from 1950 to 1960, I believe that those are reasonable figures.

Q Thanks.

A Now, that, I believe, Mr. Steer, covers the study of Turner Valley.

Q MR. STEER: Now, would it be of advantage to deal with these other fields as you have dealt with them in this report at page 16? You see, Mr. Davis, the reason I am asking you this is that in this J-2, at page 11, you refer to this January report or to the fact that the study has been reviewed in the light of current information?

A Yes.

Q Now, will it be of advantage to the Board in considering J-2 to have you go over with them this material commencing on page 16?

A I think that my views regarding Bow Island have not changed even slightly since the time that this study was made and presented on pages 16 and 17. I believe the material speaks for itself. The Board is completely aware of the fact that Bow Island is being used as a storage field, and that the quantity of gas which it presently holds, something like 15 billion feet, is not a critical point at all in the matter before them. I think we might dispense with reading that.

BOW ISLAND GAS FIELD

(All gas measurements since 1930 at 14.4 psia & 60°F.)

The Bow Island gas field is located in southeastern

Alberta. The first well in the field was completed in 1909. In 1911, this well was purchased by the Canadian Western and a year later the Company started delivering gas from the Bow Island field to markets in Calgary, Macleod, etcetera. Gas from this source formed the major supply of the Company until 1923. From 1923 to 1930, very little gas was taken from the field for commercial purposes. Total production to 1930 was 33,694,584 M cubic feet.

In 1930, Canadian Western entered in a co-operative agreement with the Royalite Oil Company. Under the terms of this agreement, gas from Royalite's plant in Turner Valley, which was available in excess of the market demands, was to be stored in Bow Island. The aim of this plan was to save some gas which would otherwise have been flared and to make this gas available for markets when Turner Valley was no longer able to carry the load. Storage was commenced August 4, 1930, and continued to February 2, 1939, when storage was discontinued by governmental orders. During this period a total of 11,818,258 M cubic feet of natural gas was stored.

The initial rock pressure of the Bow Island field was between 740 and 750 pounds per square inch gauge. By 1924, the pressure had declined to 192 pounds per square inch gauge, with a total production of over thirty-one billion cubic feet. The curtailment of production, which took place after that date, resulted in the pressure increasing until in 1930 it was 249 pounds per square inch gauge, although the total production had increased to 33.6 billion cubic feet. This increase in pressure, despite continued withdrawals, is accounted for by water encroachment which

resulted in drowning out many wells and also probably due to a greater degree of stabilization within the reservoir.

During the first stage of storage operations (1930-1939) the rate of change in pressure per cubic foot of gas injected was greater than the rate of change observed during the period of primary production. This is largely due to the decreased size of the reservoir caused by water encroachment. Pressure cones may be built up around input wells resulting in an exaggerated average pressure when determined by arithmetical averaging. This effect is believed to be small in the highly permeable Bow Island sand, a belief that is substantiated by the fact that from 1939 to 1944, when no gas was stored or produced, the arithmetic average pressure declined only fourteen pounds per square inch, from 565 pounds per square inch gauge to 551 pounds per square inch gauge. In other words, pressures stabilize readily in the Bow Island field.

The relationship between pressures and production is shown graphically on page 18 of this report. In September, 1949, with net withdrawals of 18.2 billion cubic feet, pressure stood at 603 p.s.i.g. which was the approximate pressure some 32 years earlier when only about 13 billion cu ic feet had been produced. This indicates that reservoir space capable of holding 3 billion cubic feet at 600 p.s.i.g. pressure is now filled with water. Doubtless a substantially larger reservoir volume was water filled in 1930. The convexity upward of the pressure curve from 1930 to 1949 indicates the gradual enlargement of the reservoir space as gas pressures are increased. It appears probable that if an additional 18 billion cubic feet could be returned to

the reservoir, the pressure would then stabilize at around 750 p.s.i.g.

The remaining reserves available to Canadian Western in the Bow Island field, as of January 1, 1950, are estimated at 15 billion cubic feet, or the net amount of gas in storage plus 1 billion of original gas.

Q What about Foremost, on page 19?

A I think the same would be true of Foremost.

FOREMOST FIELD

This field, located 38 miles south of the Bow Island field, has for many years served as a source of emergency gas. Being a small field, it is much more valuable as a source of peak load gas than of base load gas, as continued heavy withdrawals would quickly destroy its usefulness.

A study of the reserves of this field, made in February, 1947, by Mr. R. G. Paterson, presents all of the basic data necessary to a study of reserves. Mr. Paterson's conclusions are considered conservative and are accepted for the purpose of this report.

Reserve to January 1, 1947	15.8 billion cu. ft.
Production 1947-8-9	.467 billion cu.ft.
Reserve January 1, 1950	15.333 billion cu.ft.

Gas Potentially Available from Area South and Southeast of the Foremost Field

To the south and southeast of the Foremost Field, is an area embracing more than 50,000 acres, considered to be proven or essentially proven for commercial gas production, there exists a total recoverable gas reserve exceeding, in my judgment, 250 billion cubic feet. In the summer of 1949,

a study was made of this gas area, with as much care as could be accorded the work with the information then and presently available.

The major portion of these gas properties are controlled by McColl-Frontenac Oil Company and Union Oil Company of California. A substantial area proven for commercial gas production is controlled by California Standard Company. This California Standard acreage is at the northwest end of the proven area and can be tapped by a line extending from Canadian Western line at Foremost, a distance of 5 to 12 miles.

The gas referred to in this section may, on negotiation, become partially or wholly available to Canadian Western. A plan to take gas from the northwest portion of the area for winter and summer deliveries to Canadian Western's southern markets, and for summer deliveries to Bow Island for repressuring, might be of substantial benefit to all parties.

Q What about Jumping Pound on Page 21?

A I think that is different. I think maybe we ought to think about Jumping Pound a little bit. Jumping Pound, there are as many estimates of Jumping Pound as there are estimators. I do not care whether we read it or not.

Q Perhaps you had better read it.

A The Jumping Pound Field is located in the foothill area some 20 miles west of Calgary. The geology of the area is extremely complicated by folding, faulting and overthrust movement of older formations over the more recent sediments. Similar in many respects to the Turner Valley structure, it is more complicated, the productive beds

(Mississippian) lie considerably deeper, and in the light of present knowledge, the prospective productive zone is much smaller.

Attempts to develop oil or gas production have been made intermittently for about 25 years. During the last few years, Shell Oil Company of Canada carried out extensive detailed geologic and seismic surveys of the area, resulting in the mapping, in plan and cross-section, of the structure. Based upon this survey, the discovery well (4-24-J) was drilled, finding gas production at a depth of 9,737 to 9,838 feet. This well was reported as having 13 million cubic feet daily open flow, of sour gas, with 90 barrels of liquid hydrocarbons. The second well (10-14-J) located about three-fourths of a mile southwest of the discovery well (looking for oil) was too low on structure - salt water in the porous zone. The third well (16-14-J) was located midway between the first two and was reported as having initial open flow of 1.2 million cubic feet per day with 4 barrels of condensate. This well apparently entered the porous zone at the outer edge of the contact between the gas and salt water, thus fixing the outer limit of gas at 6,400 feet below sea level. The fourth well was located 2 miles southeast of the discovery well on the axis of the structure and was reported as having an initial open flow of 12.7 million cubic feet per day with 115 barrels of condensate.

The size of these wells is not impressive. Later back pressure potential tests have been reported as indicating substantially higher capacities to produce. Before accepting this information as conclusive, it must be carefully repeated by personnel thoroughly experienced in such work.

Size of Reservoir

Prospective Area The seismic and geologic mapping by Shell indicates a structure in the Mississippian lime whose porous zone above the -6400 foot contour is about 12 miles long and averaging about three-quarters of a mile in width.

I believe this interpretation is acceptable, although, of course, no attempt has been made to check or verify it.

The area within the -6400 foot contour approximates 5700 acres. The outer border of this area has very limited thickness of porous zone above that level. Hence, for purposes of calculation, the prospective gas reservoir is considered as having an effective area of 5,000 acres.

Thickness and Character of Pay A study of Schlumberger logs has indicated to us a probable pay thickness of 115 feet. A study of well samples made by Mr. R. G. Paterson and the writer, of samples in the Alberta Conservation Board office, indicates an average thickness of about 120 feet. These samples were also studied to gain some knowledge of the porosity present. Although no quantitative measurement of porosity is possible by visual inspection, it is considered possible to judge, within reasonable limits, the character and grade of porosity when aided by a magnification of 13 to 1. By comparison with similar studies of limestone samples of known porosity, it was the writer's conclusion that the samples studied of the gas pay zone of Jumping Pound would average less than 10 per cent.

Allowance should be made for the practical effect in increasing the total gas filled void space by fractures and solution channels. In this case, we adopted 9 per cent as

a fair judgment of the net effective porosity, the fractures and solution channels being balanced against the connate water, which, in beds of the type studied, probably averages about 35 per cent.

Attempts have been made to get some idea of the effective porosity of the Jumping Pound gas reservoir by comparison with Turner Valley. The upper porous zone of Turner Valley is regarded as non-present, due to erosion, at Jumping Pound. The lower porous zone at Turner Valley is known to be of low porosity and permeability in the down dip portion of the central area of the field, as also at the very south end of the field. Porosity and permeability can and doubtless do vary widely within the boundaries of each field, and comparisons are of little value. However, were we to base our tentative conclusions on such a comparison, we should confine the comparison to the lower porous zone at Turner Valley.

Information available will hardly permit doing this. It has not, so far as I know, been done by others.

The best that we can do in judging the thickness of the pay and its porosity is to study the electric logs and samples of drill cuttings, and to assume that the answer thus obtained will be found representative of the field. This has been done.

I am hesitating. I guess I am surprised to find recommendations in the middle of Page 23, and after that a section dealing with the proven reserves, but I will proceed to read it as I find it. I do not understand this. You will understand, I believe, that I think somebody made a mistake in copying this. In any case, I will read the recommendations.

I do not like to do it that way, and if you will permit me to, I would like to jump that section and come back to it.

Estimate of Proven and Prospective Reserves

Basic Data

Type of Reservoir Non-associated

If there be oil present it was not found by the exploration.

Top of Porous Zone (sub-sea)	-5,717
Bottom of Porous Zone (gas-water interface)	-6,400
Approximate average ground elevation	4,000
Prospective area, acres - proven and prospective I would like to say	-5,000 Est.
Average effective sand thickness (feet)	120
Productive acre-feet	600,000
Average gross porosity, excluding fractures (%)	9 Est.
Average connate water (%)	35 Est.
Net Effective Porosity (%) including fractures	9 Est.
Void space per acre-foot (Cu.Ft.)	3,920
Initial bottom-hole pressure (P.s.i.a.)	4,004
Reservoir temperature (^{o}F.)	160
Gas specific gravity (^{o}A.P.I.)	0.69
Compressibility factor, Z, at 4,004 p.s.i.a.	0.87
Gas in place per acre-foot (Mcf) estimated	1,050.5

Proven and Prospective Gas Reserves

Initial gas in place, MMMCF @ 14.4 p.s.i.a. and 60^{o} F. - 630.

The figures for reservoir pressure and temperature, and for the super compressibility factor, Z, given above, are those submitted to the P. & N. G. Conservation Board of Alberta by The Shell Oil Company, the pressure and temperature being measured and the factor Z determined experimentally.

(Go to Page 87)

Recoverable and Marketable Reserves

I am of the opinion that only 85% of the gas in place can be considered recoverable, and that at least 25% of the gas produced should be allowed for shrinkage, losses and field use, including the removal of hydrogen sulphide.

Gas and liquid hydrocarbons in place	630 MMMcf
Recoverable (85% of 630)	535 MMMcf
Gas marketable (75% of 535)	401 MMMcf

Now I come to some recommendations.

Recommendations Jumping Pound promises to be important because of its favorable location and the possibility of large gas reserves. It is still of very uncertain value because:

1. Reserves problematical.
2. Very expensive to develop (wells $500,000 each).
3. Gas purification involves a plant expected to cost in excess of $1,000,000.00.
4. Gas likely to be expensive.

All this was written before any contract was made with Shell, you will understand.

A first step should be the careful testing of wells 4-24-J and 5-7-I to determine their actual capacities.

A second step should be the drilling of one well about 2 miles north of 4-24-J and then another well about 2 miles south of 5-7-I.

Based upon the results of the above program, it could be determined if daily capacities of say 50,000 Mcf.

are available, and if purifying plant and pipe line are feasible.

Q MR. STEER: Then on page 25 you deal with the Pincher Creek field?

A MR. DAVIS: Yes, sir.

Q As of this date.

A Do you think that is something to read into the record?

MR. C. E. SMITH: I think it is, if you are waiting for somebody to say something.

A It is up to the Board, I think.

MR. STEER: Would the Board wish Mr. Davis to deal with that Pincher Creek field?

THE CHAIRMAN: If you would like to deal with it, but it is unnecessary, I think, to read all this information.

A It is just two pages and we have twelve minutes. I can just about do that.

PINCHER CREEK FIELD

The Pincher Creek field was discovered by the Canadian Gulf Oil Company following geological and geophysical surveys in that area. It lies in the foothills belt some 115 miles to the south of Calgary and approximately 40 miles from the nearest point on the Canadian Western 16" transmission line. The following three wells have been drilled to date:

Well	Reported Open Flow
Gulf Pincher Creek #1	45 MM/D from upper porous zone before acidizing. Additional gas in lower porous zone.
Gulf Walter Marr	83 MM/D after acidizing plus 3,000 bbls. distillate/day.

Gulf Fred Schrempp. At the time I wrote this was still testing. I believe that turned out to be a dry hole. It is down dip, down the flank.

The gas occurs in the Mississippian limestone, the structure being apparently a "wet gas" reservoir similar in type to Jumping Pound but somewhat deeper and richer in liquid hydrocarbons. Gulf Fred Schrempp, drilled down dip from the discovery well, Pincher Creek #1, in search of an oil zone found, instead, water in the lower part of the porous horizon. Two porous zones, similar in position to those at Turner Valley, have been encountered.

Available data regarding the field and the wells drilled is limited largely to information submitted by, or on behalf of, the Gulf Company at recent hearings regarding natural gas reserves in the Province of Alberta, where the basic data used in the reserve estimates are given without elaboration. We are therefore unable to check any figures such as the probable productive area, pay thickness, etc. On the other hand, we have no reason to dispute any of the data and they are therefore accepted pending further development of the field. Dr. Nauss gives the following reserve estimate:

Area	17,250 acres
Pay thickness	394 feet
Porosity	2.6%
Connate water	20%
Reservoir pressure,	4,945 pounds per square inch absolute
Reservoir temperature,	191°F.

Compressibility Factor, Z	0.93
Initial gas in Place to 400 psi., MMcf to 200 pounds abandonment pressure	1,788
Recoverable, MMMcf (70% of 1788)	1,252

The low porosity, combined with the relatively large open flows of the two gas wells, would indicate that fracturing of the reservoir rock plays an even greater part at Pincher Creek than it does at Turner Valley or Jumping Pound. Since such fracturing would be expected to be greatest on the crest of the structure, wells drilled on the flank may have a smaller capacity than the present two.

Regarded as a potential source of gas for the Canadian Western system, the Pincher Creek field, despite its undoubtedly large reserve, is not as attractive as could be desired, first on account of its distance from the main market, the city of Calgary, and second because of the high capital and operating costs involved in producing the gas.

Assuming that the transmission pressures now carried in the 16" line are close to a safe limit, an additional line from the field to Calgary would be necessitated if Pincher Creek were required to supply a large proportion of the Calgary demand.

The two factors which appear to rule out the possibility of cheap gas from Pincher Creek are the drilling depths - over 12,000 feet - and the high hydrogen sulphide content of the gas - of the order of 9% with 7% carbon dioxide. Offsetting these factors would be the distillate

recovered. The feasibility of commercial recovery of sulphur from this gas can depend upon a number of factors, including the size of the operation. Unless sulphur can be produced commercially, the cost of removing and disposing of the sulphur would be considerable.

I regard the Pincher Creek field as having a very large reserve, probably exceeding one trillion cubic feet. This gas may be regarded as potentially available, in part at least, to Canadian Western, should it be required. Other potential sources, such as Jumping Pound or the Pakowki Lake area, may be more feasible sources to Canadian Western.

Q MR. STEER: Then you have already dealt with the Leduc area and it will not be necessary to read that.

Now, Mr. Chairman, Mr. Davis made a report as of September 30th, 1948 for Northwestern Utilities on the Viking-Kinsella gas field and gas reserves, and the report is here. Mr. Davis is ready to put it in if the Board thinks it would be of value. My suggestion is that it may be of value to the Board because of the fact that these last two reports were made for entirely different purposes than the Board has under consideration at the present time. And they might be of value.

THE CHAIRMAN: I think it should be entered as an exhibit but I do not think it is necessary for Mr. Davis to read it.

MR. STEER: He will be subject to cross-examination on it?

THE CHAIRMAN: Yes.

REPORT IN QUESTION NOW
MARKED EXHIBIT J-7.

MR. STEER: That completes Mr. Davis' testimony.

MR. NOLAN: I wonder if, after the adjournment, the Board would remain a moment until I may distribute to the Board the remaining submission of the part of the evidence which we propose to lead. It would be much more convenient to do it here than to make the distribution elsewhere. So that, with your permission, after the adjournment we will make the distribution.

THE CHAIRMAN: Will Mr. Davis be here any longer than tomorrow?

MR. STEER: He can be, yes, sir. He can be here on Wednesday, if necessary.

THE CHAIRMAN: We hope tomorrow to have evidence of the Alberta Power Commission and from the Research Council. Possibly it could be done along with the cross-examination of Mr. Davis tomorrow. I just wondered, if there was not sufficient time, if he would be available on Wednesday.

MR. STEER: That is right, sir. So that that evidence will be given the first thing in the morning.

THE CHAIRMAN: We can either put Mr. Davis on first and see if he is through by adjournment time, or else we could go on with the other evidence first.

MR. STEER: Just whatever the Board wishes. If you want to relieve your other witnesses, that is quite all right for Mr. Davis to commence his cross-examination afterwards if that is convenient.

THE CHAIRMAN: We have copies of the submission of the Research Council. The Power Commission exhibit is supposed to be here, but unfortunately it is not. If they are received this afternoon at the Board office we will distribute them to the various counsel and give them an opportunity to study them, in case they want to cross-examine them on that. If we can get them, we will put on these gentlemen first thing in the morning. If not, we will have Mr. Davis go on with his cross-examination.

MR. STEER: Very good, sir. Whatever the Board wishes.

MR. NOLAN: Will the Research Council's submission be distributed, sir?

THE CHAIRMAN: It is going to be distributed right now.

(At this stage the Hearing was adjourned until 9.30 A.M. 31st October, 1950.)